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NOTE

These materials were prepared during the summer of 1981 and so prior to the agreement in September between the Governments of Canada and Alberta. An up-date is in preparation under the direction of Mr. Robert Parsons of Price Waterhouse and Co. Mr. Parsons intends to participate in the two weeks to be devoted to oil and gas and multi-nationals in the 1982 course on Multinational Corporations.

The materials herewith consist of:

- (A) Structure of the Canadian Petroleum Industry.
- (B) National Energy Program (qualified as above).

I.F.G.B.



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STRUCTURE OF THE CANADIAN PETROLEUM INDUSTRY

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STRUCTURE OF THE CANADIAN PETROLEUM INDUSTRY

I. Introduction: The Extent of Foreign Control

Foreign investment in many sectors of Canadian industry has grown steadily since the turn of the century. For example, in 1945, portfolio and direct investment together were estimated to amount to less than ten billion dollars. By 1970, direct foreign investment alone was valued at about twenty-five billion dollars, and portfolio investment accounted for another twenty billion dollars.¹ By the mid-fifties, the United States had replaced the United Kingdom as the major source of foreign investment, consistently accounting for close to 80% of the book value, with the United Kingdom sharing the remainder with other countries.²

Foreign, and especially U.S., control is particularly significant in the petroleum industry. Roughly one quarter of all U.S. investment in Canada is devoted to this sector, representing U.S. control of about 58% of the book value of capital as of 1976.³ U.S. control in oil and gas dropped noticeably throughout the 70's as Canadian control increased from 18% in 1970 to 40% in 1977. (Canadian control in the non-financial sector as a whole grew from 64% to 70% over that time period.)

U.S. controlled companies tend to be among the largest in most industries, and petroleum is no exception. Nine of the twenty largest producers were U.S. controlled in 1978-79.⁴

1. Hayden, Burns, Fox. Foreign Investment in Canada: A Guide to the Law. Published by Prentice-Hall of Canada Ltd., 1974, p. 5005.

2. Ibid., p. 5006, and Litvak, Maule, Robinson. Dual Loyalty: Canadian/U.S. Business Arrangements. published by McGraw-Hill of Canada Ltd., 1971, p. 4.

3. J. Gherson, "U.S. Investment in Canada," Foreign Investment Review, Spring 1980, Vol. 3, No. 2, pp. 1-4.

4. Ibid., p. 14

Regional distribution of foreign investment is significant for provincial economies. For example, U.S. controlled petroleum and gas investment is concentrated in Alberta, and, in 1976, U.S. controlled companies earned 58.5% of all corporate taxable income in Alberta.⁵

Although foreign control, and U.S. control in particular, in the oil and gas industry is slowly decreasing, the projected demand for increased capital for heavy oil projects, tar sands, and frontier ventures suggests that foreign investment will continue to be needed, and will continue to be a factor of major economic and political significance.⁶

Structurally, the Canadian petroleum industry is similar to that in the United States and many other countries. Like many of its international counterparts, the industry in Canada is composed primarily of affiliates of giant multinational enterprises that are active at most stages of the industry. Many studies have emphasized the monopolistic powers that these companies have enjoyed in the world market, first established prior to the Second World War, and somewhat eroded in the period up to 1973.⁷

The Canadian petroleum industry may, however, be even more concentrated than elsewhere, partially as a result of domination by a single company, Imperial Oil Limited. Although Gulf Oil Canada Limited, Shell Canada Limited, and Texaco Canada Limited have all risen to prominence in the postwar period, Imperial has been the dominant petroleum company in Canada, and has also controlled the major east-west trunk pipeline in Canada. In addition, the combined market share of the four major firms in the refining and distribution phases is larger than that in the United States. During the 1970s, Imperial, Shell, Gulf and Texaco held 35% of the

5. Ibid., p. 14.

6. Toronto Globe and Mail, "Report on Oil and Gas," March 16, 1981, p. B15.

7. See "The State of Competition in the Canadian Petroleum Industry, Volume I, Director of Investigation and Research, Combines Investigation Act, from which much of the following information is taken.

Canadian crude production sector, compared with a 27% share held by the four largest producers in the United States. These same companies controlled 64% of Canadian refining capacity in 1979 and 56% of the retail outlets in 1980, compared with a four largest firm share of 31% of refining capacity and 30% of the retail market in the United States in 1979 and 1975 respectively.

Canadian petroleum companies have derived their control position from their parents' dominant position in the world industry. Between the two world wars an international cartel linked Anglo-Persian (now British Petroleum), Standard Oil of New Jersey (now Exxon), and Royal/Dutch Shell. By 1932, this three firm cartel had expanded to include all but one of the dominant multinational petroleum firms, including Standard Oil of New Jersey (Exxon), Mobil, Standard Oil of California (Socal), Texaco, Gulf, the Shell group, and British Petroleum.

In the postwar period, numerous factors contributed to a decline in the effectiveness of the cartel, leading to a weakening of oil prices on world markets which continued until the early 1970s. New sources of supply were developed, Soviet exports to Europe were increased, government-owned national oil companies were established to purchase and refine crude oil and market petroleum products, and the companies not party to the original cartel were expanded. However, the power of the oil companies was not eliminated and they still had some potential to control certain downstream markets.

II. Ownership and Vertical Integration

The following summary is based on information in "The State of Competition in the Canadian Petroleum Industry," Volume I, Appendix B, and indicates the degree of foreign ownership and the extent of vertical integration of the major firms in the Canadian oil and gas industry.

COMPANY	1979 SALES \$ million	MAJOR SHAREHOLDER	VERTICAL INTEGRATION
BP Canada Inc. Montreal	889.6	BP Canadian Holdings Ltd. (65%), which is a wholly owned subsidiary of The British Petroleum Co. Ltd., London, Eng.	marketing, refining, transportation and exploration (oil&gas)
Chevron Canada Ltd. Vancouver	-	Standard Oil Co. of California (100%)	marketing, refining, transportation and exploration (oil&gas)
Federated Co-Operatives Ltd. Saskatoon	253.4	400 retail co-operatives plus 44 other	production, refining and distribution of petroleum products
Gulf Canada Ltd. Toronto	3,007	Gulf Oil Corporation (60%) U.S.	marketing, refining, transportation and exploration (oil&gas)
Imperial Oil Ltd. Toronto	6,557	Exxon Corporation (69%) U.S.	marketing, refining, transportation and exploration (oil&gas)
Irving Oil Ltd. St. John, N.B.	-	FMO Company Ltd. (51%); Standard Oil Company of California (49%)	marketing, refining and transportation of crude oil and petroleum products
Petrofina Canada Inc. Montreal	764.4	Petrofina S.A. (71.5%) Belgium (ownership to be transferred to PetroCanada)	marketing, refining, development and production of petroleum and petrochemical products.
Shell Canada Ltd. Toronto	3,436	Shell Investments Ltd. (70.8%) Netherlands/England	exploration, production purchase, refining, transportation and marketing of petroleum and petroleum products
Suncor Inc. Toronto	730.4	Sun Company Inc. (98.1%)	marketing, refining, transportation, and exploration (oil&gas)

COMPANY	1979 SALES \$ million	MAJOR SHAREHOLDER	VERTICAL INTEGRATION
Texaco Canada Inc. Don Mills	2,638.6	Texaco Inc. (90.5%) U.S.	marketing, refining, transportation and exploration (oil&gas)
Turbo Resources Limited Calgary	238.2	Liberty Holdings & Industries Ltd. (23%) ; R.G. Brawn (12%)	marketing, refining, transportation and exploration & development (oil & gas)
Ultramar Canada Inc. Downsview	-	Ultramar Company Limited, U.K. (100%)	marketing, refining, transportation, and exploration (oil&gas)

III. Exploration and Production

Participants in the exploration phase of the petroleum industry include the large vertically integrated companies and many independent companies.

The crude oil production phase includes the gathering of crude oil from the reservoir, the delivery of crude to the terminal facilities of the trunk pipeline, field storage and primary processing.

In 1947, crude oil was discovered at Leduc, Alberta, signalling the major expansion of the production and pipeline sectors of the domestic industry. The growth of crude oil production since 1947 falls into three distinct phases: an initial period of extremely fast expansion until 1956; a post-Suez period of slower development; and a sustained period of moderate growth from 1961 to 1973.

During the initial postwar development of the domestic production sector, from the discovery of oil at Leduc in 1947 to the Suez crisis in 1956, the Canadian economy grew dramatically. Per capita consumption of oil almost tripled during the period. By 1955, oil represented 46% of Canada's total energy consumption, compared to 30% in 1950. On the supply side, only 10% of the Canadian market for crude came from domestic sources in 1946, compared with 55% ten years later. Over the decade, annual Canadian production rose from 7 to 144 million barrels. By 1956, Canada had achieved a significant measure of self-sufficiency. Total production of crude oil in that year reached a level sufficient to supply two-thirds of Canadian demand, although much of this production was exported to the western United States and imports of crude continued to serve eastern Canada.

Within two years of the discovery at Leduc, production potential had exceeded market demand at prevailing prices. A slowdown in general economic growth after 1956, a decline in growth of demand for petroleum, a depressed export market for Canadian crude, and the emergence of competition from natural gas resulted in excess production capacity. In response to this, in 1961, the Canadian government adopted a voluntary policy that came to be known as the National Oil Policy.

The introduction of this policy coincided with the beginning of a renewed expansion of the Canadian economy and renewed growth in the petroleum industry. Under the National Oil Policy, the area west of a line drawn between the Ottawa Valley and Kingston was served by Canadian crude and the area east of this line by imports,

thus maintaining a market for Venezuelan oil marketed by the large multinationals.

Subsequently, production of crude oil increased at the rate of 8% yearly in the 1960s (compared with a rate of about 4.5% in the preceding 4 years). During the 1960s, synthetic crude from the Athabasca tar sands came onto the market and exploration in Canada shifted to the Arctic and coastal areas.

Canadian crude oil production totalled 461,308,845 barrels in 1977. Alberta was the largest producing province, accounting for almost 83% of total production. Saskatchewan and British Columbia were next with approximately 13% and 3% respectively of total crude production.

The three largest companies in the production of crude oil in 1978 were Imperial, Texaco, and Gulf. These companies were also among the four largest firms in the other sectors of the petroleum industry. Shell, the other major company in the refining and marketing sectors, was the eighth largest producer of crude oil and the largest natural gas producer.

The production sector is not as concentrated as the other sectors of the petroleum industry. Imperial Oil, the largest producer of crude oil, accounted for 15% of the total production of crude oil and natural gas liquids in 1978, while the four national majors together produced 35% of all domestic crude oil and natural gas liquids. Of the regional major companies, only Chevron, Sun Oil, Petrofina, and British Petroleum were among the largest oil and gas producers in 1978; as a group, they accounted for over 13% of total production.

Though a variety of firms produce crude oil, technological and regulatory factors channel their product into the hands of relatively few buyers. Throughout the history of Canadian crude oil production, the owners of feeder pipelines have had an inherent competitive advantage in gaining "first purchase control" over many of the oil fields served by their lines. First purchase control derives from lease/purchase contracts with producers or

other purchasers who give purchasing companies control over another company's crude oil. Since these lease/purchase contracts tended to last for the lifetime of the oil lease, "first purchase" rights have resulted in substantial control for the relatively small number of purchasers who dominated the industry.

IV. Pipelines

Oil

In Canada, the main producing areas of crude oil are remote from the largest markets. The movement of oil over great distances is , therefore, an integral part of the oil business. The major oil fields in Canada are landlocked, and pipelines furnish the only efficient means of moving large volumes of oil.

Dominating the crude oil pipeline system in Canada are two main trunk lines: one, stretching east from Edmonton, serves Ontario, the Great Lakes region of the United States, and Montreal; the other, from Edmonton to Vancouver serves parts of British Columbia and the northwestern United States.

The first trunk line, Interprovincial Pipe Line, is the longest crude oil pipeline system in the western hemisphere, extending 5,700 miles in the United States and Canada. The second main system, Trans Mountain Pipe Line, originates in Edmonton, traverses the Rocky Mountains, and swings southwest to Kamloops and Vancouver. From there, a major lateral line extends south to refineries in the United States.

Providing these two main transmission lines with crude oil are a number of feeder lines that take the oil from field gathering systems. Some of the feeder lines are quite extensive and have substantial capacity. One of the largest of these systems in Alberta, Federated Pipe Lines Ltd., can transport up to 450,000 barrels per day (1977) from the Swan Hills area to the Interprovincial and Trans Mountain systems at Edmonton. Other major systems feeding into Edmonton include the Pembina Pipe Line Ltd.,

with a capacity of 185,000 barrels daily; Rainbow Pipe Line Company Ltd. with 235,000 barrels daily capacity; Texaco Exploration Company, with 111,000 barrels daily capacity, and the Peace River Oil Pipe Line Co. Ltd., with 105,000 barrels daily capacity. In southeastern Saskatchewan, the combined systems of Producers Pipeline Ltd. and Westspur Pipe Line Company can provide up to 175,000 barrels daily to Interprovincial at Cromer, Manitoba. South Saskatchewan Pipe Line Company gathers crude in southwestern Saskatchewan for deliveries to refineries and to Interprovincial at Regina. The daily capacity of this line is 74,000 barrels.

Crude oil is imported for refineries in the Montreal area via the Montreal Pipe Line Company Limited and its American subsidiary, the Portland Pipe Line Corporation. This system, with a 1977 capacity of 536,000 barrels daily, transports foreign crude oil from the Atlantic seaboard at Portland, Maine, to Montreal. However, it has not been fully utilized since the Interprovincial system was extended to pipe Alberta crude to Montreal, operating at only 30% capacity in 1979 and 1980.

Refined petroleum products and natural gas liquids such as propane and butane are normally carried in separate pipelines. In eastern Canada, the Sarnia Products Pipe Line of Imperial Oil Limited and Sun-Canadian Pipe Line Company Limited carry refined petroleum products from the Sarnia area to Toronto, servicing various locations en route. The Trans-Northern Pipe Line Company operates in the area between Montreal and Sarnia. The eastern section carries products from the Montreal refineries westward to Ottawa, Cornwall, and Maitland. The western section moves products eastward from Ontario refineries to locations as far east as Kingston. Another pipeline, Imperial Oil Limited's Quebec South Shore Products Pipe Line, delivers products from Montreal refineries to Boucherville and Drummondville. A number of shorter pipelines are used in refinery complexes and to transport products from gas processing plants.

The major oil companies own a substantial interest in each

of the major trunk lines. Imperial owns a third of both Interprovincial Pipe Line and Montreal Pipe Line and has a smaller interest in Trans Mountain Pipe Line. Texaco owns 33% of Trans Mountain and 16% of Montreal Pipe Line. Both Gulf and Shell have smaller, but significant, interests in all three pipelines. With the exception of Montreal Pipe Line, of which British Petroleum and Petrofina each own 10%, the regional majors do not have any interests in the major trunk lines.

The major oil companies also have large interests in some of the feeder lines, but ownership or control of these lines is not as concentrated as it is in the main trunk lines. Some feeder lines are owned in large part by non-integrated oil companies that are involved primarily in production. Chief among these are Mobil, Hudson's Bay Oil and Gas, Dome, Home Oil, Union Oil, and Norcen.

The following table is taken from Volume I of "The State of Competition in the Canadian Petroleum Industry", page 32:

SHARE OF OWNERSHIP OF MAJOR TRUNK PIPELINES, BY COMPANY, 1980

	Interprovincial	Trans-Mountain	Portland
Imperial	33.2%	8.6%	32%
Gulf	7.4%	8.6%	16%
Shell	2.0%	8.6%	16%
Texaco	-	33.0%	16%
Total Majors	42.6%	58.8%	80%
British Petroleum	-	-	10%
Petrofina	-	-	10%
Standard Oil of B.C.	-	8.6%	-
Total Regional Majors	-	8.6%	20%
Others	57.4%	32.6%	-

Gas Pipelines

Natural gas is transported through three major systems: Trans Canada which services Central and Eastern Canada and the North Central States; West Coast which transports British Columbia gas and a relatively small volume of North Alberta production to points in British Columbia and connects with an American system servicing the Pacific North West; and the Alberta Natural System which moves Alberta gas through British Columbia to a point of connection on the international border and ultimate consumption in California.

The Alberta Trunk Line Company (Nova) is the pioneer of the grid method for the collection and transportation of natural gas. The company itself was incorporated by an Act of the Alberta Legislature which empowers it to act as a common carrier of gas, to act as a purchaser of gas, to construct gas pipelines and to purchase, process, transport, distribute and sell gas. The Act does not contain any provision to the effect that all gas destined for export from Alberta must be transported through this system, but it is a fact of economic life in Alberta that no permit for export of gas from the province will be granted except on condition that the gas be transported within Alberta solely through the facilities of Alberta Trunk Line. Voting shares are allocated among gas export companies, gas producers or processors, utility companies and two qualifying shares are allotted to the two directors appointed by the Lieutenant-Governor in Council. The remaining five directors are elected by the three categories of companies which own the voting shares.⁸

Westcoast Transmission Company, Alberta Natural Gas Company and the Alberta Gas Trunkline are Canadian owned companies. Currently, a new pipeline, (the Alaska Highway Pipeline), is under construction to carry natural gas from northern Alaska across western Canada into western and central United States. The

8. Information on gas pipelines is taken from Ballem, J. "Constitutional Validity of Provincial Oil and Gas Legislation", Canadian Bar Review, Volume 41, 1963, p. 199 at 200.

Canadian portion of the pipeline, projected to cost over \$4 billion, is to be controlled almost exclusively by Canadians.¹⁰

V. Refining and Processing

Oil

Canada's emergence as a major petroleum refining nation occurred in the period from 1948 to 1958. The discovery of substantial oil resources in the same period provided a sound base upon which to build an inland refining industry. Beginning in 1959, the pace of refinery construction slackened from a rate of expansion of about 7½% annually in the previous 10 years to about 4%. In 1959, the Canadian refining industry, in terms of crude oil capacity, was the third largest after the United States and the USSR. Since then, other countries have expanded their industries at an accelerated rate with the result that Canada now ranks in eighth place. "Petroleum Refineries In Canada (December 1979)" published by Energy, Mines and Resources Canada contains a detailed list of refineries, including company head offices, plant capacities, dates of first operation and expansion, etc.

Transportation costs are one of the most important determinants of the geographic market for petroleum products. Because crude oil is less expensive to transport than finished products, the oil companies generally locate their refineries close to potential markets. Pipelines or oil tankers connect the oil fields and the refineries. In order to minimize the costs of transporting finished products, refiners in one region often enter into processing, exchange, or purchase and sale agreements with their counterparts in other regions.

10. Foreign Investment Review, Winter 1977-78, p. 9.

Refineries in the Atlantic provinces are located near tidewater cities, and all receive imported crude by tanker. The major refineries in Quebec are located immediately east of Montreal where imported crude oil is received direct by tanker or by overland pipeline from the tidewater terminal at Portland, Maine; Canadian oil is supplied by the Sarnia-Montreal extension of Interprovincial Pipe Line. In Quebec City, imports have been the exclusive source of crude oil, though the Ultramar refinery has recently been granted supplies of western Canadian crude to be shipped by tanker from Montreal to Quebec or to be exchanged with other refiners.

Ontario refineries are located in the Sarnia and Toronto-Hamilton areas and are supplied with western Canadian crude oil via Interprovincial Pipe Line. The leading refining areas of the Prairie provinces are Winnipeg, Moose Jaw, Calgary, and Edmonton. The refineries in western Canada are generally not as large as those in Ontario and Quebec. The main British Columbia refining centre is near Vancouver.

The four major products refined from crude oil are gasoline, heavy fuel oil, light fuel oil, and diesel fuel oil. In 1978, these four products accounted for 78.3% of all production from Canadian refineries. Gasoline was the most important refined product, comprising about 35% of refinery output.

In 1979, there were thirty-nine petroleum refineries in Canada owned by fourteen refining companies, including the Come-By-Chance refinery not now in operation and the Petrosar petrochemical plant.

The four major companies in the Canadian petroleum industry --Imperial Oil, Gulf, Shell, and Texaco-- account for 25 of the 37 refineries and approximately 64% of total refining capacity. The regional major companies --Irving, BP, Petrofina, Sun Oil, and Chevron-- control six refineries and approximately 27.5% of the total refining capacity.

The four majors as a group are predominant in all regions

except the Atlantic provinces, where Irving Oil operates roughly half the refining capacity. With a few exceptions, the majors operate sophisticated refineries geared to producing gasolines and heating oils and thereby hold a large share of these key product markets. Some of the regional majors operate refineries with less capacity to produce lighter petroleum products.

The following table is taken from "The State of Competition in the Canadian Petroleum Industry", Volume I, page 35:

REGIONAL REFINERY CAPACITY, BY COMPANY, 1979

	Number of Refineries	Share of Capacity by %					
		Canada	Atlantic	Quebec	Ontario	Prairie	B.C.
Imperial Oil	6	21.95	18.97	12.70	20.58	42.07	24.45
Gulf	8	17.28	18.31	12.52	12.32	28.34	27.60
Shell	6	13.21	-	19.44	18.37	9.72	13.06
Texaco	5	11.71	4.52	12.07	22.26	6.67	-
Four Majors Total	25	64.15	41.80	56.73	73.53	86.80	65.11
Irving Oil	1	10.99	55.49	-	-	-	-
BP	2	6.76	-	11.51	12.46	-	-
Golden Eagle	2	6.15	2.71	16.69	-	-	-
Petrofina	1	4.16	-	15.07	-	-	-
Sun Oil	1	4.03	-	-	14.01	-	-
Consumers Co-op	1	1.61	-	-	-	10.00	-
Chevron	1	1.57	-	-	-	-	20.77
Husky Oil	2	0.94	-	-	-	3.20	5.64
Petro-Canada	1	0.64	-	-	-	-	8.48

Natural Gas Processing

Natural gas processing in Canada began in southwestern Ontario when the Tilbury field was discovered in 1905, and gas was delivered from that field to the town of Chatham in 1906. The Union Gas Company in 1924, built a large processing plant for the Tilbury gas at Port Alma. In western Canada, in 1924, the famous Royalite No. 4 well penetrated the main reservoir of the Turner Valley field. The Turner Valley gas had a high proportion of natural gasoline, which was in high demand, whereas the natural gas was at that time unwanted. The natural gasoline was recovered from the gas in inefficient well-site separators. This method of treating the gas was carried on for a number of years but the recovery of natural gasoline began to decline and Royalite Oil Company decided to build a central plant to process the gas that had passed through the well-site separators. This plant was constructed at Turner Valley village and came into operation in 1933. In 1934, Gas and Oil Products Limited, later Anglo-American Exploration Ltd., constructed a plant near Hartell and in 1936, The British American Oil Company Limited built a plant near Longview. These three plants made up the total natural gas processing industry in western Canada until after the Leduc oil discovery in 1947. Since then, numerous others have been put into operation to meet the increasing demand for natural gas liquids and for natural gas itself.

A publication by Energy, Mines and Resources, "Natural Gas Processing Plants in Canada-December 1979" provides a chronological record of the construction of gas processing plants in Canada, showing the initial year of operation, the original operator, the initial raw gas capacity and the products which are produced.

During 1979, the capacity for processing natural gas in Canada increased by 6% over the previous year to a rate of 405.2 million cubic metres per day. The amount of natural gas leaving the various plants was approximately 340 million cubic metres per day.

Although the number of new projects completed during 1979 decreased from 50 in 1978 to 30 in 1979, capital expenditures increased

to over \$270 million. Of the 30 new projects, seven were major expansions to older facilities.

With the recent initiation of the Alaska Highway gas pipeline project, exports allowed by the National Energy Board, and with the NEP's emphasis on increased use of natural gas, it is expected that the number of new projects will grow over the next few years.

The following table, compiled from data in the "Natural Gas Processing Plants in Canada - December 1979" published by Energy, Mines and Resources, indicates the number of gas processing plants set up by each of the major firms in Canada, and the shares of raw gas capacity of the major firms. The processing sector is concentrated in Alberta, where the four majors account for 20% of raw gas capacity. It is evident that concentration and domination by foreign multi-nationals is less significant in gas processing than in oil refining.

GAS PROCESSING PLANTS (1979)

	Number of Plants in Canada	Share of Raw Gas Capacity in %				
		NWT	BC	ALTA	SASK	ONT
Esso(Imperial)	12	-	1	4	-	16
Gulf	11	-	-	7	-	-
Shell	10	-	-	7	-	-
Texaco	6	-	-	2	-	-
Total Majors	39	-	1	20	-	16
Mobil	8	-	13	1	11	-
Petrofina	5	-	-	1	-	-
PetroCanada	8	-	-	13	-	-
Hudson's Bay	16	-	-	9	-	-
Dome	18	-	-	14	28	-
Chevron	9	-	-	4	-	-
Amoco	25	100	-	6	-	-
Westcoast Transmission	4	-	83	-	-	-
Other	183	-	3	32	61	84
Total Capacity MMcf/day		189	2263.5	15905.3	137	19

VI. Marketing

There are three major purchasers of refined oil: the commercial/ industrial sector, independent resellers, and the refiners' own distribution network. The most important products involved are heating oil and gasoline.

1. Heating Oil

The heating oil market is characterized by competition from electricity, natural gas, and other fuels such as wood and coal. Although oil (and other liquid fuels) accounted for 59% of the home heating market in 1964, (with natural gas accounting for 23.9% and electricity nil), by 1980, this had decreased to 37.3%. (Natural gas had increased to 39.4% and electricity to 19.5%.) However, it is still a significant market, particularly in Quebec, the Maritimes, and those parts of Ontario where natural gas has not yet been introduced, and particularly because the dollar value of light fuel oils has been increasing substantially. It is expected that oil's share of this market will continue to decrease as a result of both the federal government's policy of encouraging the use of natural gas and the increasing use of electricity in Quebec.

Major oil companies have, in some areas, tended to dominate heating oil sales; for example, in 1977, the major oil companies controlled 63% of the residential market in Quebec, although a strong independent segment remains.

Since the period immediately following the Second World War, characterized by a sharp increase in the demand for fuel oil as it replaced coal and wood, the four major refiners - Imperial Oil, British American (Gulf), Shell, and Texaco - have been well established in Ontario and Quebec. The combined capacity of these refiners in 1950 was sufficient to satisfy almost all of the demand for fuel oil.

Initially, the refiners relied heavily on independent resellers to market their production, as this avoided the higher costs inherent in operating their own distribution networks. The independent segment

thus initially grew in importance, particularly in Quebec where there was increased conversion from wood and coal and no supply of natural gas. However, in response to regional companies' forward integration, the major firms also began acquiring independent resellers.

This move by the refiners to control the retail distribution of fuel oil by acquiring independent jobbers and selling direct to the end-user market continued throughout the late 1960s and into the early 1970s. Shell acquired 163 independent fuel oil distributors, of which 102 were in Ontario and 28 in Quebec. During the same period, CFM (acquired by Shell, U.K. in 1969) bought 73 independents, of which 38 were in Ontario and 33 in Quebec. Between 1961 and 1971, Gulf acquired 24 and Texaco bought 12 independents.

In Quebec, the independent sector retained its viability because of its continued access to low-cost imported product. In contrast, the independent segment in Ontario declined substantially and has largely been restricted to those parts of Ontario having access to the Montreal import market.

2. Gasoline

There are currently over 20,000 retail gasoline outlets in Canada, providing more opportunity for participation of independent operators than in other sectors of the petroleum industry. Unlike heating oil, gasoline lacks readily available substitutes.

In 1978, gasoline sales totalled approximately 8 billion gallons. Ontario and Quebec were the largest markets for gasoline, accounting for approximately 59% of total sales. Ontario was the largest gasoline consuming province with 35% of total sales.

Gasoline is marketed at the retail level through a network of service stations. These retail outlets can be grouped into the following categories:

- National brand majors - outlets operating under the name of one of the four major companies with national representation: Imperial, Gulf, Shell or Texaco.

- Regional brand majors - outlets of other integrated oil companies that are strongly represented in only one or two regions of Canada. Irving, Petrofina, British Petroleum, Sun Oil, and Chevron are among the companies included in this category.
- Second brands - outlets owned and operated by fully integrated oil companies but not identified by the major brand logo. In this category, Imperial has used Gain, Econo, and Champlain; Shell has sold through Beaver and Gas Mart; and Texaco has used Regent.
- Private brand or unbranded independents - this category includes firms that retail gasoline but are not usually refiners or fully integrated companies. There are two main groups of independent retailers: mass merchandisers, such as Canadian Tire, Simpsons-Sears and Woodwards as well as firms like Caloil, Natomas, Murphy, Mohawk, and Turbo that offer many of the same services as the majors' brands; and the smaller "private brand" (or "unbranded") dealers who usually sell through what are known as gas bars and offer fewer services.

At the beginning of 1980, the four national majors operated nearly 60% of all retail gasoline outlets in Canada. The regional majors added another 26% to the total number of outlets owned or operated by refiners. The remaining refiners and independents controlled less than 20% of all retail outlets in Canada.

The following table, taken from Volume I of "The State of Competition in the Canadian Petroleum Industry, " page 41, indicates the major companies' shares of retail gasoline outlets.

RETAIL GASOLINE OUTLETS, BY COMPANY, 1980

	Number of Outlets	Share (%)
Imperial Oil	4,373	18
Shell	3,815	16
Texaco	3,194	13
Gulf	2,659	11
Total Majors	14,041	58
British Petroleum	2,357	10
Irving	2,000	8
Petrofina	1,086	4
Sun Oil	955	4
Other	3,781	16
Total Retail Outlets	24,220	100

Service stations can be classified by the type of ownership link between the supplier and the operator and the control exercised over the operator. The national and regional majors typically market gasoline through three channels:

- company owned stations operated by salaried employees or commission agents;
- company owned stations operated by lessee dealers;
- stations owned by independent businessmen who are tied to the oil company by a supply contract and sell under the supplier's logo.

Company owned operations, such as self serve and second brand outlets, are subject to the most direct control by the major oil companies. Over the past decade the market share of these stations, with their low prices, has grown dramatically. Many of these stations are capable of pumping over one million gallons annually -- two to three

times the volume traditionally sold at conventional branded full-service stations. Over the 1973-79 period, self-serve outlets captured from 25 to 40% of the large urban markets. The four national majors together owned over 60% of all self-serve outlets.

Lessee stations are leased by the oil company to the dealer for an annual rental fee. This fee is generally calculated on the basis of the volume of gasoline sold and a percentage of the dealer's other sales revenue. The dealer is entitled to the use of the company's brand name, receives advertising and sales support, and thereby enjoys the benefits of the company's reputation. In return, the dealer buys gasoline and frequently other products exclusively from the oil company. While lessee dealers are nominally independent retailers, there are circumstances when they become agents of the supplying company, and the company has control over prices. Under consignment and temporary allowance arrangements, lessee dealers can find their control over the retail price either reduced or completely eliminated.

Branded independent stations are generally owned by the retail dealers, although some are leased from third parties. Many of these stations are tied to their major brand supplier by the terms of a mortgage or other financial assistance advanced by the supplier. All are tied by supply contracts that may extend up to five years or more. Like the lessee, these dealers may also find their retail gasoline prices controlled by the oil company under consignment, temporary allowance, or other similar program.

Although these three channels are the primary means by which the majors sell gasoline, one company recently introduced a new marketing concept. In 1977, Imperial Oil entered into an arrangement with Suny's International, a private brand independent operating 37 stations in central Canada, whereby Imperial would sell gasoline to Suny's on a consignment basis.

THE NATIONAL ENERGY PROGRAM

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THE NATIONAL ENERGY PROGRAM:

I. INTRODUCTION AND BACKGROUND

The federal government's new National Energy Program was announced by Finance Minister Allan MacEachen in his budget speech on October 28, 1980. The program involves significant changes in the tax and regulatory climate and will have a major impact on the entire Canadian oil and gas industry, particularly on the foreign controlled multinational companies.

The four basic points covered by the NEP include prices, taxes, incentives and Canadianization. Legislation in these four areas will be directed at the objectives of securing independence from the world oil market, increasing Canadian participation in and control of the petroleum industry, and establishing a more equitable pricing and revenue sharing régime involving the federal and provincial governments, the industry and consumers.

A government publication issued by Energy, Mines and Resources outlines the major problems (energy dependence, foreign ownership and revenue sharing), at which the NEP is directed.¹

1. Energy Dependence

Since the mid-1970's, the Organization of Petroleum Exporting Countries has replaced the large multi-national oil companies as a dominant force in oil supply and pricing.

Oil prices that were \$3 a barrel in 1960 -- and still about \$3 a barrel in 1970 -- are now \$38 or more. In addition, the traditional marketing and supply roles of the major oil companies are being substantially reduced by state-to-state deals between OPEC members and consuming countries. The seven major international oil companies, which handled 64% of non-Communist oil production in 1973 and 1974, accounted for only 46% of production in 1979.

1. The National Energy Program, 1980, Energy, Mines and Resources

Two-thirds of OPEC production is in the Middle East, controlled by members of the Organization of Arab Petroleum Exporting Countries (OAPEC) and Iran. Some of these countries have made clear their intention not only to get maximum prices for their oil, but to use oil as a political and economic weapon.

OPEC's effectiveness was proved by events after the 1978 Iranian revolution. Despite availability of adequate supplies of oil, the price of world oil more than doubled. Today, OPEC is more strongly than ever in control of the world oil market. Moderate members of the organization, for example Saudi Arabia, have attempted to restrain rising prices, with limited success. Although it was thought that reductions in oil demand would reduce OPEC's power to set prices, OPEC members have simply adjusted supplies to maintain and raise prices.

Far from producing market stability, domination of oil supply by a few large producers has had the opposite effect. Customers are often willing to pay high prices, or accept extraordinary purchase terms, for fear that OPEC countries will reduce supplies, or that political instability in the region will result in erratic production.

The outlook for the next decade is not encouraging. The International Energy Agency's forecast of oil supply and demand indicates shortfalls in 1985 and 1990, despite what may be optimistic expectations of production from some key countries (Saudi Arabia and Iran).

Canada's position, unlike most of its industrial partners, is that of a net exporter of energy. However, Canada has the same weakness as most other industrial countries: dependence on imported oil. Some 425,000 barrels a day, or about 25% of Canadian oil consumption, is now imported. Under previous policies, this dependence was expected to grow to over 600,000 barrels a day by the mid-1980's-- at the same time as our exports of natural gas, electricity, and coal would be rising. Under the NEP, however, oil imports will be reduced

and replaced by domestic energy sources.

2. Foreign Ownership

Of the top 25 petroleum companies in Canada, 17 are more than 50% foreign owned and foreign controlled, and these 17 account for 72% of Canadian oil and gas sales. Thus, the rise in the price of oil and the resulting dramatic appreciation in the value of oil and gas reserves, has benefited primarily foreign industry. The federal government points out that pricing and tax policies intended to promote the domestic oil industry have also resulted in substantial transfers of wealth from Canada to foreign owned producers.

Foreign-controlled firms also control the future through their control of the land in which exploration takes place. The frontier land permits are largely held by foreign-controlled companies. Of the 290 million acres held under permit on frontier lands, 110 million acres are held by Canadian controlled companies. Of the Canadian held permits, Petro-Canada accounts for the largest portion, about 60%. It is one of the few Canadian companies capable of handling the costs and risks of frontier exploration. Dome Petroleum Limited, another Canadian controlled company, holds a further 15%. Other Canadian companies hold only very small interests in these new resource areas. Similarly, the existing oil sands plants are dominated by foreign controlled forms. Canadian controlled firms represent only 34% of the equity in Syncrude.

If this pattern were left undisturbed, foreign controlled companies would account for a large part of the future energy supplies in Canada. The reinvestment of the cash flow earned by the foreign companies on their current production will help increase the size and influence of these companies.

One of the NEP objectives, therefore, is to increase substantially Canadian ownership of the petroleum sector.

Concern is often expressed over Canada's need for foreign capital in the energy sector. Such a need is often cited as the basis

for accepting the large degree of foreign ownership in the oil and gas industry. The federal government, however, points out that the oil and gas industry, rather than drawing in foreign capital, has, since the 1974 oil crisis, been a capital exporter. The industry, in addition to maintaining its normal dividend and interest payments, supported net capital outflows abroad of \$2.1 billion in 1975-79. Some of these funds represented a return of capital to foreign owners; others represented new foreign investments by Canadian companies. If dividends and interest payments are added to this total, the outflow during 1975-79 becomes approximately \$3.7 billion. Dividends rose from \$200 million a year in 1973 to \$600 million in 1979. In addition, foreign parents have received fees for technological, operating and managerial services. It is projected that these capital exports will grow as oil and gas prices continue to increase.

The value of foreign owned firms, and therefore the cost to Canada of securing control over them, has increased three- to four-fold. A further delay will put the value of companies in the industry so high as to make the cost prohibitive, leaving Canada with no choice but to accept a permanent foreign domination by these firms.

Governments around the world have responded to the changes in the oil industry by developing a larger public sector. In Norway, Statoil now dominates oil production. In Britain, BNOC is of growing importance. In most OPEC countries, state-owned oil firms are the main, if not sole, producers. Most European countries have established state corporations or mixed-ownership companies, many of whom are engaged in the entire spectrum of oil activities. Within Canada, the provincial and federal governments have moved in a similar fashion. Most provincial governments have for some years been directly involved in electrical generation. More recently, several provinces, including Alberta, Ontario, Québec and Saskatchewan have established corporations, partly or wholly owned by the provincial government, with a mandate in oil and gas. The federal government created Petro-Canada.

The federal government's position is that direct public sector participation of this type must be increased to ensure a share in oil wealth for the public, in return for tax and incentive policies which enable growth of the industry.

3. Revenue Sharing

Provincial petroleum reserves have presented unforeseen potential for vast revenue generation. At issue is the extent to which such wealth should be shared between the federal and provincial governments.

Attempts to give effect to the concept of equalization have contributed to the present revenue sharing dispute. Some form of equalization payments from the federal government to the provinces has existed since Confederation, and has been included in the federal budget explicitly since 1957. Although, at the outset, such efforts equalized only the revenues from federal personal and corporate income tax and succession duties, the equalization base has gradually been broadened to include nearly all provincial revenue sources, including oil and gas revenues. As the base increased, the financial burden on the federal government increased. Provincial revenues were at first raised to match the average per capita yield of the two highest-yielding provinces; then, in 1967, the level was lowered to the average per capita yield of all the provinces. (More recently, an Ontario-federal agreement cuts off equalization payments to Ontario at the point where its per capita income exceeds a national 3 year average.)²

Beginning in 1973, oil prices skyrocketed and revenues of the oil producing provinces, especially Alberta, increased dramatically. The resulting burden on the federal government caused by a need to increase the level of equalization payments to all provinces, (and a consequent burden on the large Ontario tax base), accounts for present federal (and Ontario) efforts to keep prices

2. Simeon, R. "Natural Resource Revenues and Canadian Federalism:

A Survey of the Issues", 1980 Can. Public Policy, Vol. 6, pp. 182-91

for Alberta's oil as low as possible. The attempt at full equalization has also been abandoned, and now only one-half of Alberta's oil revenue is included in the equalization base.³

Obviously, a greater federal share of oil revenues would ease the federal financial burden. Presently, the division of Alberta's oil and gas rents is estimated to be 45% to the provincial government, 45% to the producers and 10% to the federal government. The September 1981 federal-Alberta agreement on pricing will result in projected shares of 30.2% for the provincial government, 44.3% for the industry, and 25.5% for Ottawa.⁴

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3. Courchene, T. and Melvin, J. "Energy Revenues: Consequences for the Rest of Canada", 1980 Can. Public Policy, Vol.6, pp.192-204
 4. Toronto Globe and Mail, September 2. 1981, Page 8.

THE NATIONAL ENERGY PROGRAM:

II. CANADIANIZATION1. Introduction

One of the major objectives of the NEP is to reduce foreign ownership and control in the Canadian petroleum industry. Specifically, the NEP aims at:

- at least 50% Canadian ownership of oil and gas production by 1990
- Canadian control of a significant number of the larger oil and gas firms, and
- increased federal government ownership in the oil and gas industry.

2. Government Ownership

With respect to government ownership, it is intended that Petro-Canada will acquire the Canadian operations of one or more multinational oil companies, with such acquisitions to be financed by borrowing in foreign capital markets. Equity capital for these ventures will be raised through a Canadian Ownership Charge imposed on all oil and gas consumption in Canada, (see Part III , page 21), and set at such a level as to ensure that the program will be self-financing.

In keeping with this policy, Petro-Canada is presently negotiating the purchase of Petrofina Canada Inc., now controlled by Petrofina S.A. of Belgium. The present bid has been approved by the Ontario Securities Commission and is to remain open for 2 years.¹

3. Canadian Ownership and Control

Under the NEP, the degree of Canadian ownership and control in oil and gas companies will become crucially important, by virtue of its significance in the following areas:

1. Toronto Globe and Mail, April 4, 1981, p. B8 and April 1, 1981, p. B21

- Canadian ownership and control will determine eligibility for the Petroleum Incentives Program (see Part IV).
- Only Canadian controlled companies with COR's (see below) greater than 50% will be eligible to sell their excess gas to a newly established Crown corporation, the Natural Gas Bank. This Bank will purchase from Canadian owned and controlled firms gas for which markets cannot be found, will enter into joint venture operations, and will provide production loans to such firms.
- Ownership and control status will be considered by the National Energy Board in granting export permits for oil and gas, and preference will be given to Canadian owned and controlled firms.
- At least 50% Canadian ownership will be required in order to obtain a licence for any production from Canada Lands, including the Yukon and Northwest Territories and offshore areas.

4. Canadian Ownership Rate

Canadian ownership will be measured in terms of a Canadian Ownership Rate, or COR, which is intended to indicate the extent of Canadian beneficial ownership. Individuals and business enterprises will require a certificate which sets out both their COR and their control status.

Much of the following summary of COR and control status determination is taken from a booklet published by the Petroleum Monitoring Agency, "Method for Measurement of Canadian Ownership and Determination of Control Under the National Energy Program", April 22, 1981. This publication also contains draft legislation giving further details on COR calculations and certificates.

(a) Applications

Only "qualified applicants" may apply for COR certificates.

Individuals who are Canadian citizens ordinarily resident in Canada or who are permanent residents, as defined, are qualified applicants. Similarly, a Canadian corporation, partnership, or trust, including trusts in respect of pension plans, may apply for a certificate. However, a joint venture may not apply. Instead, the members of a joint venture, to the extent that they qualify in their own right, may apply for their own certificates.

Applications for COR certificates are made to the Petroleum Monitoring Agency, and must be accompanied by audited financial statements, a confirmation of total authorized (issued and outstanding) shares and convertible instruments, a description of all warrants, rights, options, debt instruments, and informal equity, and particulars supporting the COR calculation and control status determination. Documentation supporting the COR measurement and control status must be retained by the applicant for six years from the date of application.

(b) Presumptions

A Canadian citizen ordinarily resident in Canada and, in most cases, a permanent resident (within the meaning of the Immigration Act) will be presumed to be Canadian for ownership and control purposes. Certain financial institutions and intermediaries serve as vehicles for pooling the savings of individuals. These include pension plans, life insurance companies and certain types of "pooled" funds (usually operated by trust companies, mutual fund companies, or life insurance companies). Where these types of vehicles meet specified conditions, including that at least 90% of their assets are held in respect of Canadians, they will be presumed to have a Canadian Ownership Rate of 100%. A similar provision will apply to passive investors that are at least 90% Canadian. In addition, certain corporations which are generally thought of as being owned exclusively, or almost exclusively, by Canadians, will be presumed to have a COR of 100%. Examples are the Alberta Energy Company Ltd. and the British Columbia Resources Investment Corporation.

In general, a business with total assets of under \$5 million and gross revenues of less than \$10 million will be presumed to have a COR of 100% if it is Canadian controlled and if it is at least 50% owned by individuals with Canadian addresses. Such businesses will be eligible to use a short form in applying for a COR.

(c) Measurement of Beneficial Canadian Ownership:

Formal and Informal Equity

Measurement of the COR of the majority of applicants will likely be based on the beneficial ownership of their formal equity. This will normally involve measuring the extent to which individual Canadians own, for their own benefit, the common shares of a corporate applicant. A partnership or trust will measure the extent of the beneficial Canadian ownership in its capital and income interests.

Arrangements that are referred to as informal equity may also influence the level of benefits that would accrue to Canadians. Indeed, such informal equity may represent more accurately the true beneficial interests in a business enterprise than does the formal equity. For instance, royalty agreements or management service contracts may entitle persons other than holders of the formal equity to a fixed percentage of the resource revenues of the applicant. Although it is expected that the COR of most applicants will be determined by the measurement of formal equity only, the informal equity may also be taken into account for purposes of COR calculation in circumstances where informal ownership interests materially dilute the proportion of benefits that would otherwise accrue to the owners of the formal equity.

(d) Method of Calculation

Because of the NEP's goal to increase the proportion of the oil and gas industry owned by Canadians, a test of ownership that only takes account of the address of registered shareholders, partners or beneficiaries is inadequate for the purpose of

measuring the bona fide beneficial interest of Canadians in a corporation, partnership or trust. Therefore, the method of calculation requires an applicant to see through the address or nominee of its shareholders, partners or beneficiaries to the underlying individual who holds the true economic interest in the enterprise.

All ownership interests (e.g. common shares) registered with foreign addresses are considered to be foreign in the actual measurement process (except where the applicant can show the contrary). Conversely, all ownership interests of less than \$50,000 in market value with Canadian addresses are presumed to be 100% Canadian. At least one-half of the remaining holdings, starting with the largest holdings, must be measured directly to determine their Canadian content and the unmeasured balance may then be assumed to have the characteristics of the larger measured holdings.

Where different classes of shares of a corporation exist but their characteristics are common, the shares of the different classes will be combined. Where a class of shares cannot be combined because its characteristics differ from others but that class is insignificant in relation to the total equity of the corporation, it will be excluded. Where two or more classes of shares which are significant cannot be combined, the COR of each class will be measured separately, and the COR of the applicant is the weighted average of the classes that have been measured separately, provided a meaningful weighted average can be calculated. If a meaningful weighted average cannot be calculated, the COR of the applicant will be the lowest COR of the various classes of shares being measured. Without this latter provision, there is no assurance that the COR of the applicant would actually reflect its true beneficial ownership.

Convertible preferred shares and convertible debt will be taken into account, in specified circumstances, regardless of whether they have an upward or downward effect on an applicant's

COR. Other forms of forward equity will also be taken into account, but only where they have a downward impact, with the PMA having discretionary power to deal with these situations.

Where there are different classes of ownership interests in partnerships and trusts, similar rules will apply as in the case of corporations.

The following example, taken from the PMA's April 1981 publication, illustrates a simple case of a corporation with 1000 shares outstanding. If foreigners own 100 shares and if persons with Canadian addresses, each having holdings worth less than \$50,000, own the equivalent of 200 shares, the balance is 700 shares. The applicant must measure the Canadian ownership of at least one-half of the remaining 700 shares starting with the largest block and moving downward in descending order of magnitude.

In this example, at least 350 shares must be measured but it is assumed that 400 shares are actually measured. The unmeasured 300 shares are then assumed to have the same ownership characteristics as the 400 measured.

$$\text{COR} = \frac{B + (B/A \times R) + S}{T}$$

Where:

A = the number of shares measured directly (in this case A = 400 shares)

B = the degree of beneficial Canadian ownership in the holdings (i.e. shares) measured

R = the unmeasured shares (300 shares)

S = individual holdings with Canadian addresses with less than \$50,000 in market value (200 shares)

T = total shares outstanding (1000 shares)

Assume that the measured degree of beneficial Canadian ownership in the 400 shares is 320 shares.

$$\begin{aligned}
 \text{COR} &= \frac{320 + (320/400 \times 300) + 200}{1000} \\
 &= \frac{320 + 240 + 200}{1000} \\
 &= 0.76 \quad (\text{i.e. } 76\%)
 \end{aligned}$$

Often it will be found that the shares that are being measured are beneficially owned by other corporations. Where corporations in a chain are at arm's length, it is necessary to trace back the ownership through two links in the chain only, on the basis of a measurement process that is considerably relaxed. Where corporations in a chain are not at arm's length, the ownership of the block must be traced through the chain to the ownership of the ultimate holding company. In this latter case, if there is an arm's length chain beyond the ultimate holding company, ownership must be traced back through two links in that arm's length chain, as described above.

The more relaxed test for an arm's length chain reflects the fact that the ownership interests that are at arm's length would likely have a diluted and less significant impact on the Canadian ownership rate of an applicant than would ownership interests that are not at arm's length.

The need for special treatment of nominee and street share holdings has been recognized. The rules attempt to accommodate problems in tracing the identity of these holdings.

(e) Determination of Canadian Control

The control test is as important an element in the federal program as is the measurement of beneficial Canadian ownership. Thus, certificates issued to applicants will indicate their control status as well as their COR. The test of "control" will, in almost all respects, be based on the definition of control in the Foreign

Investment Review Act. The test is concerned with determining the individual or group of individuals who exercise effective control. Where a determination of control status has been made by the Minister responsible for FIRA, the PMA will accept that determination. In other cases, applicants will be required to submit to the PMA certain information relating to their control status to serve as the basis for control determinations by the PMA.

(f) Administration

The PMA will issue certificates on the COR and control status of applicants which will be required by, for example, an applicant for incentive grants under the Petroleum Incentives Program (see Part IV). Due to the time lapse before the enabling legislation is passed, applications received by December 31, 1981 will be made retroactive to January 1, 1981, provided that the applicant will certify that there have been no material changes in its control or ownership status in the interval. Applications will normally (after January 1, 1982) be valid for 12 months, subject to the following qualifications:

If a certificate holder's COR decreases as a result of actions subject to its control (e.g. sale of new shares to non-Canadians), this information must be forwarded to the PMA and a new certificate will be issued. Where an applicant knows that its COR has risen, it may supply relevant information and a new certificate will be issued. Where a change in control has occurred, the PMA must be informed and, where appropriate, a new certificate will be issued.

In certain prescribed circumstances the PMA will provide advance rulings to facilitate management decisions, for example, the issue of securities or corporate reorganizations. Also, the PMA plans to issue guidelines and technical bulletins to assist in the interpretation of the regulations.

THE NATIONAL ENERGY PROGRAM:

III. TAXATION1. Background and Pre-NEP Tax Structure

A booklet published by Price Waterhouse in February 1981 best summarizes the changes in the tax structure occurring under the NEP. Much of the following information is excerpted from this booklet.

The NEP will substantially change the tax structure under which the Canadian oil and gas industry operates. These changes are interrelated with the pricing, incentives and Canadianization aspects of the NEP.

Briefly, in the area of taxation, the NEP will introduce:

- Petroleum and Gas Revenue Tax
- Natural Gas and Gas Liquids Tax
- Petroleum Compensation Charge
- elimination of most depletion allowances in the Income Tax Act
- federal-provincial sharing of the federal export tax
- federal royalties on production from Canada Lands
- Canadian ownership tax.

These changes will be effected by amending existing legislation and by enacting various new acts and regulations.

To fully appreciate the impact of the NEP on the taxation of oil and gas revenues, it is necessary to understand the fundamental features of the tax régime prior to the introduction of the NEP in October 1980.

In 1980, oil and gas operations in Canada were subject to two major charges: federal and provincial income taxes, and provincial royalties which were intended to provide economic rents to the producing provinces. Both these levels of charges will continue after 1980, except that most of the earned depletion allowances

which are provided for in the income tax legislation will be phased out under the NEP.

In addition to the above two kinds of taxation, the petroleum industry is subject to a third charge -- the "Syncrude levy". This is a charge of \$1.75 a barrel which is collected by the federal government to compensate purchasers of synthetic crude oil, where such purchases are required to be made at world price levels. The Syncrude levy will be replaced under the NEP by the Petroleum Compensation Charge.

(a) Income Taxes

The federal and provincial governments each levy an income tax in respect of profits derived from the production of oil and gas. The rules contained in the various federal and provincial acts for the computation of income tax are basically the same, except for the treatment of crown royalties which are paid by the taxpayer. The federal government collects the federal income tax and, on behalf of B.C. and Saskatchewan, collects provincial income taxes. As of January 1, 1981, Alberta enacted its own income tax act under which it will collect that province's corporate income tax.

(i) Rates

The rate of federal income tax which is applied to taxable income is 46%. This rate is reduced by 10%, in order to allow for the income taxes which are levied by the provinces, so that the net rate of basic federal income tax is 36%, before taking into account a "temporary" 5% surtax which results in a basic federal income tax rate of 37.8% until December 31, 1981.

The basic rates of income tax levied by the producing provinces are 15% in B.C., 11% in Alberta, and 14% in Saskatchewan. The income tax legislation of the producing provinces contains provisions whereby rebates may be obtained against provincial income taxes in respect of additional income taxes payable as a result of the payment of provincial crown royalties which are not allowed as deductions in computing taxable income for purposes

of federal and provincial income taxes. In addition, an Alberta royalty tax credit may be obtained equal to 25% of oil and gas royalties paid to the province, subject to a maximum annual credit of \$1 million.

(ii) Taxable Income

Taxable income is generally income from all sources computed in accordance with generally accepted accounting principles as modified by specific provisions of the income tax legislation. The principal deductions which may be claimed in computing taxable income, but which may be expensed at different amounts and at different times in computing accounting income, include:

- capital cost allowances (in lieu of book depreciation)
- a resource allowance
- exploration and development expenses
- depletion allowances.

Ordinarily, the above deductions are claimed instead of comparable amounts which are reported in the company's books of account, and are computed with reference to specific and complex rules contained in the legislation. In addition to disallowances for book depreciation and amortization, no deduction may be claimed for income tax purposes for crown royalties that are paid by the taxpayer.

Following is an example of how federal income tax would be calculated prior to the NEP:

ILLUSTRATIVE CALCULATION OF
FEDERAL INCOME TAX - 1980

Accounting income-

Revenue	\$2,000
Operating expenses	(200)
Depreciation and amortization	(600)
Provincial royalties	(200)
Net profit before income tax	<u>\$1,000</u>

Taxable income and federal income tax-

Net profit (as above)	\$1,000
Add: Depreciation and amortization	600
Disallowed royalties	200
Deduct: Capital cost allowance	(200)
Resource profits	1,600
Resource allowance (25% of 1,600)	(400)
	1,200
Exploration expenses	(300)
Depletion allowance ¹	(100)
Taxable Income ²	<u>\$ 800</u>
Federal income tax payable (37.8%)	302

-
1. It is assumed that the taxpayer's "earned depletion base" consists of only the \$300 exploration expenses incurred currently.
 2. It is assumed that no interest expense was incurred and that no inventory allowance is claimed.

(iii) Capital Cost Allowance

Most machinery and equipment acquired by the taxpayer for the purpose of exploring for and producing oil and gas is eligible for capital cost allowance at the rate of 30% per annum on a declining balance basis. Machinery and equipment used at a natural gas processing plant generally qualifies for an accelerated capital cost allowance which permits the cost of such equipment to be written-off over a two year period. This accelerated write-off also applies to refinery assets.

Tax liability may be reduced by an investment tax credit in respect of the cost of specified eligible depreciable property. The rate of tax credit ranges from 7% to 20% of eligible costs, depending on, inter alia, where in Canada the asset is used. Such credits reduce the capital cost of the property for purposes of calculating capital cost allowance and earned depletion entitlements.

Certain tangible assets which are consumed in the exploration for oil and gas may qualify for treatment as Canadian exploration or development expense.

(iv) Exploration and Development Expense

The application of specific income tax rules to the deduction of a particular exploration or development expense depends on a variety of factors, including the period during which such expense was incurred, the nature of the expense, and the nature of the business being carried on by the taxpayer. There are in excess of twenty five different categories of exploration and development expenses, all of which are subject to different rules. However, most exploration and development expenses incurred by a taxpayer in 1980 in respect of oil and gas fall into one of the following three categories:

- Canadian exploration expense - deductible in full in the year incurred, and in subsequent years to the extent not deducted in a prior year
- Canadian development expense - deductible at the rate of

30% per annum on a declining balance basis

- Canadian oil and gas property expense - deductible at the rate of 10% per annum on a declining balance basis.

(v) Resource Allowance

In recognition of the fact that provincial crown royalties are not deductible for income tax purposes and in order to provide some incentive for incurring exploration and development expenses, a taxpayer is permitted to deduct a special "resource allowance" equal to 25% of net oil and gas production profits and royalty income, computed after deducting capital cost allowances and operating expenses, but before deducting exploration and development expenses, interest expense, and earned depletion allowances. The 25% resource allowance is a special deduction which is permitted for income tax purposes, and which has no counterpart in computing net profit for accounting purposes.

(vi) Depletion Allowances

In 1980, the income tax legislation provided for two special deductions which were intended to provide an incentive for, inter alia, exploring for oil and gas in Canada. These "earned depletion" allowances can be described as follows:

- Basic earned depletion - entitles the taxpayer to an extra \$1 deduction for each \$3 spent on eligible exploration and development activities, and on certain bituminous sands equipment. The annual deduction is limited to the lesser of 25% of the taxpayer's resource profits, and the unclaimed balance of the basic earned depletion entitlement.
- Supplementary depletion - the taxpayer is entitled to claim an extra \$1 for each \$2 or \$3 spent on eligible activities, mainly expenditures on enhanced recovery systems and tertiary recovery techniques, and on certain bituminous sands equipment. For corporations, the annual deduction is limited to the lesser of 50% of net income, and the unclaimed balance of the earned supplementary entitlements.

(b) Provincial Royalties

(i) Alberta

The Alberta oil royalty on production from Crown leases (computed on a well by well basis) is dependent upon a number of factors including the amount of monthly production from the well, the current market value of crude oil, and whether the oil is considered to be "new" oil (oil from a pool discovered after April 1, 1974 and oil from other pools recovered as a result of an enhanced recovery scheme that was authorized after January 1, 1974), or "old " oil.

The maximum Alberta oil royalty rates currently approximate 50% for old oil and approximate 36% for new oil. The maximum rates are approached when monthly production exceeds 12,000 barrels.

With gas, as with oil, there is a distinction between old and new. Unlike oil, however, gas royalties are not based on rate of production but rather on selling price. The royalty rate for both old gas and new gas (generally gas from a pool discovered after January 1, 1974) is 22% of the selling price up to 26¢ /mcf. The rate increases on a graduated scale thereafter to 50% for old gas and 35% for new gas of the selling price in excess of 36¢ /mcf.

Although the royalty rates are determined from the gross selling price, a gas processing allowance deduction is permitted in calculating the amount of royalties payable.

(ii) British Columbia

The British Columbia oil royalty on production from Crown leases is based on production per month from a well. Price increases do not affect the royalty rate calculation. The distinction between "new" oil (generally, oil production from a pool that did not contain a well completed prior to November 1, 1975) and "old" oil is also relevant in the royalty determination. Rates increase based on production to approach a maximum of 40% for old oil and 30% for new oil. (Production of 12,000 barrels per month is subject to royalty rates of approximately 39% for old oil and 29% for new oil.)

Although regulations exist for gas royalties, virtually all gas produced in the province is sold to the British Columbia Petroleum Corporation (BCPC) at a set price and is exempted from royalty. The price set by BCPC generally is significantly lower than the fair market value of the gas. The difference, a "phantom royalty", is treated similarly to a royalty and is included in income for income tax purposes. The rate of "phantom royalty" varies from month to month depending upon the average value of gas sales made by BCPC. (The mix between domestic and export sales in a month is a significant factor in determining the average value.) The effective rate determined in a month late in 1980 exceeded 45% for new gas (generally, gas from a pool no part of which flowed prior to November 14, 1973) and exceeded 55% for old gas.

(iii) Saskatchewan

The province of Saskatchewan imposes a royalty on production from Crown acreage and an oil well income tax on production from all acreage. Any Crown royalty payable is allowed as a credit against the oil well income tax. Effectively, production from Crown acreage is subject to the higher of the royalty or the oil well income tax, in general the latter. Oil well income is subject to tax at a rate of 61%. To the extent that the income is derived from "new" oil (generally, oil produced after 1973 from an oil well completed after 1973 or from a pool subject to an enhanced recovery project) an incentive allowance may be deducted from income which results in an effective rate of 43% applicable to the new oil income.

A number of deductions, in addition to the "new" oil incentive allowance, are permitted in computing oil well income, including deductions for operating expenses, certain administrative or overhead charges, interest expense, capital cost allowance, exploration and development expenses, and a small business allowance. Although the eligible expenditures for capital cost allowance and exploration and development expenses are similar to those for federal income tax purposes, the rates of deduction vary significantly.

Gas produced from a Crown lease in Saskatchewan is subject to a royalty of 2¢ /mcf. Gas production in the province is not significant.

2. Taxation Under the NEP

With the exception of proposed changes to existing earned depletion allowances, and restrictive changes to the definition of Canadian exploration expenses, the NEP itself will not involve any changes to the income tax and provincial royalty systems which were in effect in 1980.

The NEP proposes a variety of new federal taxes and charges which will result in increased direct and indirect burdens on Canadian producers and consumers of oil and gas. The following, taken from the Price Waterhouse summary, outlines the fundamental features of these new taxes and charges.

(a) Petroleum and Gas Revenue Tax

A new tax of 8% (initially) of Canadian oil and gas production revenue is effective as of January 1, 1981.³ The tax is to apply to any person who has income from oil and gas in Canada or from processing Canadian petroleum as far as the crude oil stage or its equivalent. The tax is not to be imposed on income from transporting or transmitting oil or gas, refining crude oil, or processing gas.

The federal government takes the position that federal tax revenues have been eroded by "generous investment incentives" and that rather than reducing these incentives, the Petroleum and Gas Revenue Tax is introduced in order to obtain for the federal government a part of its revenue needs.

The 8% rate will be reviewed, as oil and gas prices rise faster than \$1 a barrel every six months.

Since the payment of this tax is not deductible for income tax purposes, and because of the fixed selling price for oil and gas, the full impact of this tax will be borne by the producer.

3. In the September 1981 agreement between Ottawa and Alberta, it was agreed that this tax will be doubled to 16% (subject to a 25% resource allowance). In addition a new 50% federal tax will be imposed on the incremental revenues (after royalties) resulting from price increases. These two taxes are expected to raise about \$20 billion for the federal treasury over the next 5 years. -- Toronto Globe and Mail, September 2, 1981, p. 8.

Bill C-57, to enact the Petroleum and Gas Revenue Tax Act, has received first and second reading, and has been before the House Committee for revision as of July 1981. The Petroleum and Gas Revenue Tax will be imposed in two parts -- the Part I tax being a "production revenue tax" and the Part II tax being a "resource royalty tax".

Production Revenue Tax

This is a tax on the "production revenue" (as defined) derived by any person from the production of Canadian petroleum or gas, or the processing in Canada of petroleum up to the crude oil stage. The following are certain high-lights of the tax:

- It applies to all persons who have revenue from oil and gas production, including charities, pension funds, and Crown agencies who may currently be exempt under the Income Tax Act.
- The tax is payable in respect of a person's taxation year as determined for income tax purposes. If the person does not have a taxation year for income tax purposes, the taxation year will be the period for which accounts are ordinarily made up or such period as may be adopted, but in no case may a taxation year exceed fifty three weeks.
- The tax applies to production revenue attributable to any period after 1980.
- The Bill contains provisions whereby the amount of tax payable would be reduced by incentive grants to which the taxpayer was entitled under the Petroleum Incentives Program.
- Corporations will be required to make monthly instalments; and individuals will make quarterly instalments, of production revenue tax for the current taxation year in the same manner as they presently make income tax instalments. The first instalment will be payable

on March 31, 1981 and might require the computation of a hypothetical production revenue tax liability of the taxpayer for 1979 and 1980 taxation years as though the legislation was in force for those years.

- The tax will be administered by Revenue Canada, Taxation. The administration and enforcement provisions contained in the Bill are very similar to the corresponding provisions in the Income Tax Act. Provisions are made for stringent penalties and interest to be payable by taxpayers who attempt to evade payment of the tax or who do not pay taxes promptly.
- Taxpayers will be required to make a return of production revenue for each taxation year and estimate therein the total amount of production revenue tax payable for that year.
- The production revenue tax may not be deducted as an expense for income tax purposes.

Computation of Production Revenue

A key element in the computation of the production revenue tax will be the computation of production revenue of the taxpayer. In very broad terms, production revenue represents gross revenues at the wellhead, minus lifting costs and certain prescribed exploration and development overhead expenses. More specifically, production revenue is defined as the net amount of income (less losses) from any source that is (a) the production of Canadian petroleum or gas, or (b) the processing in Canada of petroleum up to the crude oil stage.

Income or loss from a source does not include the following:

- Income or loss from transporting or transmitting petroleum or gas, refining crude oil, or processing gas
- Any "resource royalty" (as defined) income from which a resource royalty tax has been withheld at source by the payor (see below)

- Recaptured depreciation on the disposition of depreciable property
- In the case of Crown agencies, any Crown royalties that were not deductible to the payors of the royalties for income tax purposes.

In computing income, the following rules will apply:

- In the case of an integrated producer who refines petroleum to any stage beyond the crude oil stage or its equivalent, the petroleum shall be deemed to have been disposed of by the producer for fair market value at the crude oil stage. In other words, any revenue attributable to processing petroleum after the crude oil stage will not be subject to the production revenue tax.
- A taxpayer may take a reserve against income in respect of revenue received for petroleum or gas to be delivered after the year-end. Any such reserve taken at the end of one year must be added back to income in the following year.
- Any Crown royalties required to be included in the income tax base under paragraph 12(1)(o) of the Income Tax Act must also be included in income for production revenue tax purposes.

Finally, in taking any deductions against income, only those expenses reasonably applicable thereto are allowed. In particular, no deduction is allowed for the following:

- Depletion, depreciation, exploration or development expenses (except prescribed exploration and development overhead expenses), interest or other financial expenses, inventory and resource allowances, research expenses, and any government royalties, taxes, lease rentals or bonus payments with respect to the production of petroleum or gas.
- Any "payout" in respect of a resource royalty received

that has not been included in income (see below).

- Resource royalties accrued at the end of the year and not paid out within sixty days thereafter. Such disallowed resource royalties may, of course, be deducted in the year in which they are actually paid. (In general, resource royalties paid in the year or sixty days thereafter may be deducted from income for production revenue tax purposes.)
- Crown royalties that would not be a valid deduction for income tax purposes.

Resource Royalty Tax

This is a tax payable by every person in receipt of a "resource royalty". "Resource royalty" is defined as any amount computed by reference to the amount or value of production after December 31, 1980, of Canadian petroleum or gas and includes any minimum or advance royalty payment in respect thereof. The following are certain high-lights of this part of the tax:

- As with the production revenue tax, the resource royalty tax applies to all persons receiving resource royalties, whether or not they are taxable under the Income Tax Act.
- The tax is borne by the recipient of the royalty, but is required to be withheld at source by the payor of the royalty. The payor must remit the tax withheld to the Receiver General on or before the fifteenth day of the following month.
- Every person who pays a resource royalty must complete a prescribed return whenever the tax deducted at source is remitted to the Receiver General. An information return in prescribed form for each calendar year must also be filed with the Minister of National Revenue, and one copy of the portion of the return relating to the taxpayer must be forwarded to each taxpayer in respect of whose resource royalty the return relates.

- Any recipient of a resource royalty on which tax has been withheld who is required to pay to another person a portion of the royalty (referred to as a "payout") will be required to withhold a percentage (likely 16%) of the amount of the payout. However, the amount withheld need not be remitted to the Receiver General, as the appropriate tax would already have been remitted on the entire amount by the first person who makes a royalty payment.
- The resource royalty tax may not be deducted as an expense for income tax purposes.

(b) Natural Gas and Gas Liquids Tax

All natural gas sales, including exports, are to be subject to a new Natural Gas and Gas Liquids Tax imposed under the Excise Tax Act.

The NEP proposes that the new natural gas tax be levied initially at a rate of 30¢ /mcf commencing November 1, 1980 with respect to domestic sales and February 1, 1981 with respect to export sales. Increases of 15¢ /mcf will be imposed July 1, 1981, January 1, 1982 and January 1, 1983. Separate rates will apply to gas liquids.

The tax generally applies to distributors of natural gas on the acquisition of gas for resale to consumers, or to producers and distributors who themselves are consumers, but will take into account the various purchase and sale arrangements in the industry.

This tax will be imposed on marketable pipeline gas:

- received by a distributor
- received by a consumer from a gas producer or broker
- taken for own use by a gas producer or broker
- exported for use in transporting gas to Canada through a pipeline.

The tax is payable at the time that the marketable pipeline gas is received, appropriated for own use, or exported as the case

may be, by:

- the distributor as above
- the consumer, as above (in this case the tax is collected by the producer or broker, as the case may be)
- the gas producer or broker as above
- the holder of the export licence, as above.

The natural gas liquids tax will be imposed on ethane, propane, butanes or mixtures thereof, received by a person for removal from the plant, following its production in a gas processing or reprocessing plant.

This tax is payable by the owner of the natural gas liquids at the time it is first received for removal from the plant, and the operator of the plant shall collect the tax from the owner on behalf of the Minister.

The administration of the tax will involve a licencing system whereby producers or operators, distributors and brokers must apply for a licence which will be used in the administration and collection of the tax.

(c) Petroleum Compensation Charge

In 1980, Canadian oil price arrangements were based on federal-provincial pricing agreements which established a two price system for oil: the lower price being a domestic price, and the higher price being an export price. Where a Canadian refiner processed imported oil, for which it had to pay the world price, it received a federal subsidy under the oil import compensation program to reduce its cost to the same level as refiners using Canadian oil which was purchased at the domestic price. These federal subsidies were paid out of general funds and were therefore borne by all Canadian taxpayers.

Under the NEP, one of the purposes of the new price system for oil would be to ultimately shift the burden for these subsidies from the taxpayer at large to the oil consumer. In order to accomplish this, a Petroleum Compensation Charge will be levied on

domestic refiners to cover the cost of the federal oil import compensation. This charge was \$2.55 a barrel at the end of 1980, and it will increase by \$2.50 a barrel on January 1 of each year starting in 1981.

As in the case of the pre-1981 subsidy (the "Syncrude levy"), the amount of this charge is established by regulation under the Petroleum Administration Act. Since the amount of the charge can apparently be changed by order-in-council, the Minister would appear to have considerable discretion as to the future amounts of the Petroleum Compensation Charge.⁴

The Petroleum Compensation Charge will be administered by the Petroleum Compensation Board, which will consist of officials of Energy, Mines and Resources who are appointed by the Minister.

(d) Depletion Allowances

As part of the NEP's new incentive system for oil and gas, the earned depletion allowances provided for in the income tax legislation will be drastically altered. The following changes will be made effective January 1, 1981:

- For corporations, the depletion allowance for domestic exploration expenditures will be earned at 33 1/3 % of qualifying expenditures incurred in 1981, net of any incentive payments.
- After 1981, the depletion allowance for domestic exploration expenditures outside the Canada Lands will be phased out. The rate will be reduced to 20% in 1982, 10% in 1983, and to 0% in 1984.
- The depletion allowance for development expenditures, other than expenditures related to incentive-price projects, will be eliminated, effective January 1, 1981.
- The depletion allowance for approved expenditures on integrated oil sands projects, enhanced recovery projects, and heavy crude oil upgraders will be earned at 33 1/3 %

4. In the Ottawa-Alberta agreement of early September, 1981, the federal government agreed to raise only sufficient funds through this tax to cover the cost of imports, in contrast to earlier NEP plans which would have resulted in surplus funds for Ottawa -- Toronto Globe and Mail, September 2, 1981, page 8.

of qualifying expenditures, net of any incentive payments, incurred in 1981 and thereafter. (Previously, this rate could have been 50%.)

In all cases, earned depletion will be deductible up to a ceiling of 25% of resource income. (Prior to 1981, the supplementary depletion allowance could be deducted up to a ceiling of 50% of all income.)

Individuals will not be eligible to "earn" depletion allowances after 1980.

It was felt by the federal government that incentives provided by the depletion allowance system were not selective enough or sufficiently sensitive to government policies respecting Canadian ownership, and were inequitable where the taxpayer who had incurred eligible expenditures did not have a source of resource profits and therefore was entitled to no deduction in respect of the depletion allowance.

(e) Canadian Exploration Expense

The October 28, 1980 federal budget proposed changes to the definition of "Canadian exploration expense" (CEE) which would have seriously curtailed the eligibility of expenditures for the relatively favourable treatment that is accorded CEE as compared to Canadian development expense (CDE). (CEE will continue to earn depletion, is fully deductible as incurred, and will be eligible for incentive grants.)

The budget announced that, after 1980, CEE would only include those drilling and related costs that were incurred in respect of an oil or gas well drilled in an area where a commercial accumulation of oil or gas was not previously known to exist and only if the well was abandoned within twelve months of its completion or if it was the first well in the area capable of production in commercial quantities. Costs incurred in drilling other wells would qualify as CDE. Previously, the cost of drilling a capped gas well would have qualified as CEE where it was not

reasonably expected to come into production within twelve months, and the cost of drilling any dry hole would have been CEE. Under the budget proposals, the cost of drilling a capped gas well would generally have been treated as CDE unless the well was drilled in an unproven area.

In partial response to a strong negative reaction from the petroleum sector, the federal government modified somewhat the above proposals. Under Bill C-54, the new and restrictive definitions of CEE would not take effect until 1982 instead of 1981 as originally proposed. Also, under Bill C-54, the costs of drilling all dry holes will continue to be treated as CEE, and frontier drilling costs will be eligible as CEE except for the cost of drilling a commercial production well and the cost of drilling a delineation well which was commenced after any commercial production from the accumulation.

However, it is significant that no change was made to the original proposal that effectively results in the costs of capped gas wells drilled in non-frontier lands being treated as CDE. Under Bill C-54, such costs incurred after 1981 will be accorded the less favourable status of CDE as compared to CEE unless the costs are incurred in exploring for an accumulation of petroleum or natural gas not previously known to exist.

These changes to the definitions of CEE represent further steps to tighten up the income tax write-offs which are available in respect of oil and gas expenditures. They follow upon an amendment, effective December 12, 1979, whereby the cost of acquiring an oil and gas property would no longer qualify as CDE but would be categorized as "Canadian oil and gas property expense" (COGPE). COGPE is deductible at the rate of 10% per annum on a declining balance basis, versus 30% for CDE.

(f) Federal Export Tax

Under regulations relating to the Petroleum Administration Act, the federal government levies a "federal export tax" equal to

the additional revenues generated from the difference between the export price and the domestic price of oil. Under the NEP, one-half of this tax would go to the two oil producing provinces, although it is also indicated in the NEP that oil exports will be phased out by the end of 1985. This proposed sharing arrangement regarding the federal export tax will not affect producers or consumers.

(g) Royalties from Canada Lands

On December 9, 1980, first reading was given to Bill C-48 to enact the Canada Oil and Gas Act.⁵ Under the Bill, two different royalties will be levied on the holder of a production licence in respect of Canada Lands: a basic royalty and a progressive incremental royalty.

Basic Royalty

Each holder of a production licence will be liable for a basic royalty equal to 10% of the value of production derived from Canada Lands. The value of such production will be determined monthly by the Minister of Energy, Mines and Resources, and the royalty is payable monthly by the twenty fifth day of the following month.

Progressive Incremental Royalty

In addition to the basic 10% royalty, each holder of a production licence will be liable for a royalty equal to 40% of "net profit"(as defined). Net profit will be determined annually in accordance with specific rules set out in the Act.

In general terms, "net profit" will mean the total income received by the licence holder in the year from the oil or gas produced from the lands under the licence, minus the following deductions which will be required to be claimed in the order set out below:

- 10% basic royalty
- Operating costs
- Federal income tax allowance

5. This Bill was substantially amended after lengthy consideration by the Standing Committee on National Resources and Public Works, as reported on June 29, 1981.

- Investment allowance
- Capital allowance.

Operating costs include exploration, delineation, development, and production expenses, but do not include interest costs or overriding royalties.

The amount of the federal income tax allowance will be calculated with reference to the amount of federal income tax that would be payable in respect of the year by the licence holder if the income received from the oil or gas produced from the lands under the licence were the only income for the year. In calculating this hypothetical amount of income tax, the taxpayer is required to assume that:

- Maximum permissible deductions shall be taken in respect of exploration and development expenses, operating expenses, capital cost allowances, and depletion allowances
- Interest costs and overriding royalties shall not be deductible.

The investment allowance will be equal to 25% of the "total eligible investment" made by the licence holder within an area determined by the Minister. Costs which are eligible for inclusion in the "total eligible investment" account include:

- The cost of drilling the discovery, delineation, or development wells, and the cost of other preproduction development expenditures
- Exploration costs incurred prior to drilling a discovery well
- Continuing developmental and delineation expenses
- Certain prescribed costs.

For the first year in which the licence holder obtains production from the determined area, eligible costs for that year's investment allowance will be those costs incurred in the year and in prior years. For the second and subsequent years in which

the licence holder obtains production, eligible costs include the current year's costs, plus prior year's costs depreciated at 10% per annum on a declining balance basis.

The amount of capital allowance which may be claimed in a particular year is equal to the lesser of:

- 1/6 of "total eligible investment" costs
- The unclaimed balance of "total eligible investment" costs.

The unclaimed balance of total eligible investment costs is equal to the aggregate amount of such costs incurred to date, minus capital allowances claimed to date. For purposes of the investment allowance and the capital allowance, costs or expenses which are eligible for inclusion in the calculation of these allowances, and which were incurred in any year that ended more than six years before the date on which production commenced, may be indexed at specified rates of up to 50% depending on the number of years between the date of incurrence and the date of production.

In calculating "net profit" for purposes of the incremental royalty, there is no provision for the deduction of other years' losses. Also, where the original discovery of oil or gas was made prior to 1981, the licence holder, on filing a notice in a prescribed manner, is exempt from the payment of the incremental royalty for a period of three consecutive years following the day on which the royalty would have first become payable.

The NEP explains that these complex rules for determining the progressive incremental royalty are designed to levy a royalty only to the extent of net annual profit in excess of a 25% "floor rate of return".

(h) Canadian Ownership Tax

The federal government intends, in order to ensure greater Canadian participation in oil and gas development, to acquire the Canadian operations of several large foreign controlled oil and gas firms. To help finance these acquisitions, a Canadian ownership levy on oil and gas production, at an unspecified

level, will be imposed in the future. The charges will be set at levels that make this program totally self-financing, and the actual rates and the dates of implementation will be determined by the progress of the acquisition program. It is reasonably clear that such a Canadian ownership tax will be borne directly by the consumer of oil or gas.

(i) Effect of Taxation Changes on Foreign Investment

Foreign investment in the Canadian petroleum sector will be affected, generally adversely, by a number of recently proposed changes to the direct and indirect taxation of such investment. In addition to differentiation between Canadian versus foreign owned and controlled investment in several areas of the NEP (e.g. the Petroleum Incentives Program, the Natural Gas Bank, export licences, and entitlement to Canada Lands production), tax changes proposed in the December 11, 1979 budget and changes effected in the new Canada - U.S. Tax Treaty will also have an effect on foreign investment in this sector.

December 1979 Budget

It was proposed that the Income Tax Act be amended to prevent a non-resident of Canada from disposing of Canadian oil and gas interests in a manner whereby Canadian income taxes at full rates are avoided.

Formerly, a non-resident operating a resource business in Canada through a permanent establishment was subject to full Canadian tax, whereas a non-resident participating only by way of a royalty interest could avoid the full impact of Canadian taxation. This difference in treatment made it attractive to non-residents to dispose of their resource interests in Canada for royalty interests. The immediate tax consequences of the disposition could thereby be deferred until a year when the non-resident had no permanent establishment in Canada and would be taxable at the favourable rates applicable to royalties. It was therefore proposed that:

- All forms of income, including royalties from the exploration and holding of Canadian resource properties and proceeds from the

disposition of such properties of a non-resident who carries on a resource business in Canada, will be treated as business income subject to tax in Canada, and

- When a non-resident person ceases to carry on a resource business through a permanent establishment in Canada after December 11, 1979, there will be an immediate deemed realization of all the taxpayer's Canadian resource properties at fair value. A similar rule will apply if the non-resident person was carrying on the resource business through a partnership.

Canada-U.S. Tax Treaty

The new Canada-U.S. treaty affects the Canadian taxation of a U.S. investor in Canadian petroleum interests in two respects.

Disposition of Resource Property

Under the previous treaty, gains derived by a resident of the U.S. from the disposition of natural resource properties located in Canada were exempt from Canadian tax, unless the vendor maintained a permanent establishment in Canada. Since a permanent establishment is defined to include an oil well, the disposition of most Canadian petroleum interests were taxed in Canada. However, gains from the disposition of certain royalty interests, for example, a gross overriding royalty, qualified for the exemption and were subject to tax only in the U.S.

The new treaty defines real property to include "rights to explore for or to exploit mineral deposits, sources and other natural resources..." and provides that gains from the disposition of real property in Canada may be taxed in Canada. Whether this provision will enable Canada to tax gains from the disposition of certain royalty interests that were previously exempt is not clear, because it is unclear whether the definition of real property encompasses all royalty interests.

Resource Royalties

The previous treaty limited the rate of tax which could be imposed by Canada on natural resource royalties to 15%, unless the U.S.

recipient had a permanent establishment here. As in the case of the disposition of resource property, certain types of resource royalty income qualified for this limitation on withholding tax.

Under the change to the Income Tax Act, a non-resident carrying on a resource business in Canada is subject to full Canadian tax on royalty income from Canadian resource properties. The previous treaty would have protected U.S. residents against full taxation; however the new treaty does not restrict the right of Canada to tax resource royalty income arising here. Consequently, a U.S. resident carrying a resource business in Canada will pay full Canadian tax at graduated rates on royalty income. A U.S. resident not carrying on a resource business in Canada will pay a 25 % withholding tax on such income.

THE NATIONAL ENERGY PROGRAM:

IV. PETROLEUM INCENTIVES PROGRAM1. Introduction

As referred to in the information on Taxation (pages III - 16,17), depletion allowances under the income tax system for exploration and development expenses will be phased out. Incorporation of incentives in the tax system benefited only taxpaying companies, which, in the view of the federal government, favored large foreign owned firms.

The new Petroleum Incentives Program is aimed at encouraging exploration and development of new reserves, while attempting to ensure Canadian control of these new ventures. At the same time, the Program encourages development of non-conventional sources and favors development of federal lands rather than provincial lands.

2. Phase Out of Depletion Allowances

Prior to January 1, 1981 taxpayers were allowed to claim a depletion allowance which was generally equal to 33 1/3 % of oil and gas exploration expenses, development expenses, and certain capital expenditures related thereto.

Under the less attractive depletion provisions contained in the NEP, the rate at which the allowance is "earned" by corporations will depend on the nature of the expenditure and whether the expenditure is incurred on Canada or Provincial Lands. Individuals are no longer eligible to "earn" depletion.

Depletion for domestic exploration expenditures incurred in 1981 will continue at the 33 1/3 % rate, but the base will be net of incentive payments. After 1981, depletion for domestic exploration expenditures on Provincial Lands will be reduced over a three year period. This phase-out will apply equally to all corporations, notwithstanding their degree of Canadian ownership.

Expenses for exploration on Canada Lands and development expenses for prescribed projects eligible for incentive prices,

including enhanced recovery, oil sands and heavy oil projects, will continue to earn depletion at the rate of \$1.00 for every \$3.00 of eligible expenditures.

Prior to January 1, 1981 supplementary depletion was earned at the rate of 50% of the cost of enhanced oil recovery machinery and equipment and 33 1/3 % of the cost of "bituminous sands equipment", and was deductible annually up to a maximum of 50% of total income. After 1980, such expenditures will earn depletion at the lower rate of 33 1/3 % provided that they are part of a prescribed project entitled to incentive prices. The cost of machinery and equipment acquired for a facility to upgrade heavy oil to a crude oil equivalent will also earn depletion at a 33 1/3 % rate.

In all cases, after 1980, earned depletion is deductible annually up to a reduced ceiling of 25% of resource income.

3. Petroleum Incentives Program

The new Petroleum Incentives Program allows eligible applicants to submit claims to the Petroleum Incentives Board for regular cash payments to recover a portion of eligible expenditures incurred after December 31, 1980 in exploring for and developing Canadian oil and gas reserves. Energy, Mines and Resources' discussion brief of December 19, 1980, "Petroleum Incentives Program, The Basic Rules - A Framework", states that an applicant for an incentive payment can be a corporation, partnership, trust or individual. Parties engaged in a joint venture will have to apply separately.

Claims may be submitted and paid quarterly (subject to 20% holdback) or annually.

The amount of grant to which an applicant is entitled generally depends on four main factors:

- The Canadian Ownership Rate (COR) of the applicant at the time the eligible expenditure is incurred
- The nature of the expenditure (whether it is on account of exploration , development or "other" activities
- The location of the land, whether Canada Lands or

Provincial Lands, where the work is carried on--

(Canada Lands are considered by the NEP to include the Yukon and Northwest Territories, and offshore areas, some of which are the subject of federal-provincial jurisdictional disputes.)

- The share of profits from those lands that the applicant is entitled to receive.

The following Table, taken from the February 1981 Price Waterhouse summary of the NEP, illustrates how these factors determine the amount of the incentive payment.

INCENTIVE PAYMENTS AS A PERCENT
OF ELIGIBLE EXPENDITURES
(as of February 16, 1981)

		COR level ¹			
		1	2	3	4
Canada Lands					
Exploration					
	1981	25%	35%	65%	80%
	1982	25%	45%	65%	80%
	1983	25%	45%	65%	80%
	1984 seq	25%	50%	65%	80%
Development					
	1981	--	--	15%	20%
	1982	--	10%	15%	20%
	1983	--	10%	15%	20%
	1984 seq	--	10%	15%	20%
Provincial Lands					
Exploration					
	1981	--	--	25%	35%
	1982	--	10%	25%	35%
	1983	--	10%	25%	35%
	1984 seq	--	15%	25%	35%
Development ²					
	1981	--	--	15%	20%
	1982	--	10%	15%	20%
	1983	--	10%	15%	20%
	1984 seq	--	10%	15%	20%

1. COR levels are as follows:

Level 1: less than 50% COR

Level 2: 50% or higher COR

Level 3: 60% COR in 1981, increasing 1% per year to 65% in 1986

Level 4: 65% COR in 1981, increasing 2% per year to 75% in 1986

2. These same grants are available for qualified costs in respect of non-conventional and tertiary oil projects and for crude oil upgraders.

3. Canadian individuals are deemed to have Level 4 COR.

It is apparent that, except for exploration costs incurred on Canada Lands, non-Canadian controlled companies or Canadian controlled companies that do not have the requisite COR will not qualify for any grant in respect of exploration and development expenses. Moreover, the amount of grant available will be greater for those Canadian controlled corporations that have a 75% or greater COR than for those companies that have a COR in the 50-75% range.

The grant available in respect of qualified expenditures incurred on non-conventional and tertiary oil projects is the same as that available for development expenditures on Provincial Lands. However, these costs will also continue to earn depletion at the rate of \$1.00 for every \$3.00 of qualified costs incurred.

The Petroleum Monitoring Agency will be responsible for certifying the Canadian Ownership Rate and Canadian control of applicants. Applicants for incentive grants with 50% to 100% COR will be required to submit a COR certificate with their claims. No COR certificate is required for the 25% Canada Lands exploration incentive. Applicants will be responsible for submitting revised COR certificates if their COR rating crosses the critical thresholds.

4. Eligible Expenditures

For the purposes of the Petroleum Incentives Program, eligible expenditures will fall into three categories:

- Exploration Expenditures
- Development Expenditures
- Other Expenditures

Eligible Expenditures will be, to the greatest extent possible, consistent with those definitions and interpretations used for income tax purposes. Eligible "Exploration Expenditures" and "Development Expenditures" will parallel the income tax definitions of "Canadian Exploration Expense" and "Canadian Development Expense" as they relate to oil and gas operations. "Other Expenditures" will include various capital assets now identified in several classes for the purposes of computing Capital Cost Allowances.

This "Other" category of activity is to include non-conventional and tertiary oil projects, and crude oil upgraders in Western Canada. Generally, the following types of capital assets would qualify in this category:

- Acquisition costs of non-conventional petroleum assets such as mega projects (oil sands)
- Crude oil upgraders in the Western Provinces
- Enhanced recovery equipment
- Offshore production platforms
- Conventional well equipment.

The December 1980 P.I.P. publication lists a number of general principles to clarify the determination of Eligible Expenditures:

- Expenditures will be determined on the accrual basis.
- The point of time when costs are incurred will be defined to prevent artificial acceleration of entitlement.
- Expenditures will be net of any current year recoveries and net of any associated provincial incentives receivable.
- To prevent inflation of costs, fair market value rules will apply for non-arm's length transactions. Non-arm's length transactions will include those between parties where there is essentially the same management or control, employees, dependence for financing, or property, etc.
- Overhead expenditures may not include:
 - financial or administrative expenses that are not principally directed towards exploration or development activities;
 - charges for services or equipment from a party not dealing at arm's length to the extent they exceed the amount that would have been the cost had it been incurred directly.
- Expenditures may not include unreasonable or artificial expenditures.

- Unequal sharing of non-eligible costs between entities with different COR levels will reduce incentive payments.
- Seismic expenditures will be eligible for incentives only to the extent that they have not previously received an incentive grant.

5. Transfer of Incentive Payments

The Petroleum Incentives Board acknowledges that there is a vast variety of financing and ownership arrangements associated with the oil and gas industry that are used to provide new sources of capital and for allocating risks and benefits. However, the PIB is concerned to avoid the indirect transfer of incentive payments and benefits to entities with lower COR levels than the applicant. The Price Waterhouse summary identifies three possible ways that such a transfer of benefits can take place:

- Transfer through a working interest
- Transfer through the size of the block of land
- Transfer through work requirements.

Formulae have been developed to adjust the amount of eligible expenditures downwards if certain criteria are not met. These formulae involve the calculation of the applicant's "adjusted eligible expenditure": after the applicant's "adjusted eligible expenditure" is determined, it is multiplied by the incentive rate to determine the appropriate PIP grant.

In determining the amount of the grant to which the applicant is entitled, information will have to be provided regarding the applicant's "commensurate interest" in the lands on which it has incurred the exploration and development expenditures. In general, two tests will be applied with respect to the determination of whether an adequate commensurate interest is being obtained. One test will involve the measurement of the amount of costs which an applicant has incurred relative to its working interest in a total lease and, in the case of farm-outs, the other test will involve reference to the amount of acreage earned under the farm-out agreement.

In the case of the working interest test, there are two situations contemplated by the present PIP proposals, referred to as A and B as follows:

A. Where an applicant already has a working interest in respect of a given lease, its share of costs must not be greater than its proportionate working interest in the particular lease.

B. Where a working interest is earned on a farm-in basis, the general test against which the commensurate interest benefit will be measured will be a 2:1 ratio of cost to interest .

The "commensurate interest test" is also made by reference to acreage acquired through farm-ins. PIP would stipulate that the block of lands on which the applicant earns a working interest be of a specified minimum size. For exploratory wells, the minimum size block will vary with the geographic location.

Where the acreage tests are not met, it will result in a proportionate reduction in the amount of the expenditures upon which grants are to be paid.

With regards to the possibility of indirect transfers of PIP benefits through the terms of work requirements, it is planned that multi-well deals costing more than \$50 million per year, involving extensive land spreads and other assets, will require prior approval from the board, regardless of the COR of the participants.

This provides the Board with an opportunity to establish whether PIP benefits will be transferred to companies with lower levels of Canadian ownership than required by PIP rules.

In general, the PIP rules will be designed to ensure that a high-COR entity does not bear a disproportionate share of work requirements.

The December 1981 PIP publication also contemplates the possibility of indirect transfers of incentive benefits by other means. For example, rules similar to the ones above could apply where an applicant:

- increases its profit interest through a penalty or

or dilution formula contained in a working arrangement
- incurs eligible expenditures on a property in exchange
for shares of a corporation which owns an interest in
the property.

THE NATIONAL ENERGY PROGRAM:

V. PRICING1. Oil Pricing(a) Background

The development of principles to govern oil pricing has been a matter of national debate since the Arab embargo of 1973-74. The position of the federal government is based on a commitment to a single price for crude oil in Canada, subject to transportation differences, and gradual increases in that price in order to encourage the development of new supplies and encourage conservation, while allowing time for consumer adjustment.

A central issue is the relationship between the price of oil in Canada and the world price. The government does not favor tying domestic prices to the world price. Its position is that present discovered reserves should not give rise to windfall gains, but that higher prices for higher cost and high risk sources will provide incentive to encourage new discoveries.

The federal government also opposes a world price for gas, since part of the NEP includes an oil substitution effort, encouraging substitution of lower priced gas, (of which Canada has far greater reserves), for oil.

The post-1973 upsurge in international oil prices led to the establishment of controls on the price of oil produced in Canada, through a series of federal-provincial agreements.

Since 1973, domestic oil prices at the wellhead have risen in regular stages. The price in mid-1973 was \$3.40 a barrel; today, it is \$16.75.

As the price of imported oil is beyond Canadian control, the federal government established the Oil Import Compensation Program (OICP), under which refiners processing imported oil are paid federal subsidies to reduce their costs to the same level

as refiners using Canadian oil.

The delivered price of domestic conventional oil in central Canada in 1980 was about \$18.00 a barrel. The landed cost of imported oil was then \$38.00 a barrel. The federal subsidy on imports was then about \$20.00 a barrel, or approximately 53 % of the cost. A gap of this magnitude between international and Canadian prices is a comparatively recent phenomenon. As recently as July, 1978, the per barrel differential was less than \$3.00.

As an incentive for the development and production of synthetic oil from oil sands, the federal government has established prices higher than those available for conventional oil. Domestic synthetic oil producers sell their production to refiners at a price equal to the imported oil price. The government subsidizes refiners purchasing synthetic oil to the extent needed to reduce their costs to the same level paid by refiners purchasing domestic conventional oil. This subsidy is financed by a federal levy imposed on all oil refined in Canada (the "Synchrude Levy"). The refiners pass on the costs of this levy to consumers in the form of higher prices for petroleum products.

(b) The New Blended Price System

Under the NEP, the government has established a new schedule of prices for domestic oil production, and a new price system to blend the costs of different sources of oil into one weighted-average price to consumers. The government is committed to a substantial but predictable rise in prices. In addition, its oil pricing policy is intended to obtain a competitive advantage for Canadian industry through prices that are below those prevailing in other industrial countries. Projected prices to July 1990 appear in the following table, taken from the 1980 Energy, Mines and Resources publication on the National Energy Program:

NATIONAL ENERGY PROGRAM: WELLHEAD OIL PRICES

	Oil Sands Reference Price ¹	Tertiary Recovery Oil ²	Conventional Oil
	(\$ / bbl)		
Jan. 1980	----	----	14.75
Aug. 1980	----	----	16.75
Jan. 1981	38.00	30.00	17.75
July 1981			18.75
Jan. 1982	41.85	33.05	19.75
July 1982			20.75
Jan. 1983	45.80	36.15	21.75
July 1983			22.75
Jan. 1984	49.85	39.35	25.00
July 1984			27.25
Jan. 1985	54.10	42.70	29.50
July 1985			31.75
Jan. 1986	58.55	46.20	35.25
July 1986			38.75
Jan. 1987	63.20	49.90	42.25
July 1987			45.75
Jan. 1988	68.30	53.90	49.25
July 1988			52.75
Jan. 1989	73.75	58.20	56.25
July 1989			59.75
Jan. 1990	79.65	62.85	63.25
July 1990			66.75

1. Subject to cap of international price.
2. In later years, the price for tertiary recovery oil will depend upon the price for conventional oil. As the price for conventional oil approaches that for tertiary recovery, price differentials will develop to reflect quality differences, i.e. the cost of upgrading. The price of tertiary recovery oil will never be less than the price for conventional oil of a similar quality.

(c) Prices for Domestic Oil Production

(i) Conventional Oil

Beginning January 1, 1981, the wellhead price for a barrel of conventional oil will rise \$1.00 every six months until the end of 1983. Thereafter, until the end of 1985, price increases will take place at the rate of \$2.25 every six months. Commencing in 1986, the price will be raised at the rate of \$3.50 every six months, until it reaches its appropriate quality-determined level relative to the oil sands "reference price", explained below. If by 1990, the conventional oil price is still below that for reference price oil, consideration will be given to a more rapid rate of escalation.

The price schedule will provide a very high price towards the end of the decade. Prices at the wellhead in 1990 will be four times present levels, but it is projected that Canadian dependence upon oil will have been reduced substantially.

(ii) Higher Cost Oil

The price of conventional oil is, at present, a price paid largely for oil already found. Some of the new sources of oil are not economic at conventional oil prices, and require higher prices. Large quantities of oil from high-cost sources in Canada-- oil sands, enhanced oil recovery, and frontier oil-- can be profitably produced at less than projected international prices. The National Energy Program includes Canadian prices for integrated oil sands and heavy oil projects, and for enhanced oil recovery projects. These prices reflect Canadian cost conditions, and are called reference prices. They are designed to provide returns to new sources when they come on stream, and to provide certainty to the industry.

The reference price for synthetic crude oil from the oil sands provided by the NEP will be the lesser of \$38.00 a barrel (effective January 1, 1981, and escalated annually thereafter by the Consumer Price Index) , or the international price.

The NEP also includes incentives for oil produced using approved tertiary enhanced recovery methods. A "tertiary supplement"

will be paid by the federal government to qualifying producers. This supplement will be additional to the conventional oil wellhead price. For a company producing a representative 15 degree crude oil through approved tertiary methods, the total wellhead price as of January 1, 1981 was approximately \$30.00 a barrel. The supplement on that date was approximately \$14.00 a barrel, applied equally to all qualities of crude oil. The tertiary reference price will be adjusted annually, in a manner similar to the method of changing the oil sands reference price.

The new incentive will not affect current wellhead price differentials arising from quality differences. However, as wellhead prices begin to escalate faster than \$1.00 a barrel every six months, an examination will be made of quality differentials to see whether they are suitable in view of the costs of upgrading oil in central upgraders or Canadian refineries generally.

Implementation of this tertiary recovery incentive depends upon co-operation of the oil-producing provinces. The incentive will be offered only in provinces that maintain or, preferably enrich, existing fiscal incentives for tertiary production.

An incentive will also be offered to facilities that upgrade heavy crude oil. The amount of this incentive will depend on the cost of the upgrading process, having in mind that the total price for upgraded heavy oil from tertiary recovery should not exceed the price offered to oil sands production. Petro-Canada and Saskoil (Saskatchewan's Crown oil corporation) will carry out a feasibility study of an upgrading plant in that province. On the basis of that study, the level and nature of incentive will be established.

A reference price for specified frontier oil and other domestic sources may be established when more is known about the costs of bringing these new supplies on stream, and the timing of production.

Incentive prices for the large integrated oil sands plants are conditional upon the project in question satisfying guidelines relating to the use of domestic goods and services, and to participation

and employment of native peoples. In addition, acceptable progress toward Canadian ownership objectives will be a condition of the reference price offer.

(iii) Blending the Cost of Imported Oil and Reference Price Oil

Another feature of the blended price system will be to include the total cost of oil imports, over time, into the price that all oil consumers pay. This will be done by a simple extension of the existing system of refinery levies. When the system is fully phased in, all domestic refiners will pay a new Petroleum Compensation Charge, which incorporates the Syncrude Levy, to cover the costs of oil import compensation. Revenues from this Charge will be used to pay importing refiners an amount sufficient to reduce the average cost of imported oil to the average cost of oil to Canadian refiners. By the end of 1980, this charge was \$2.55 a barrel, consisting of \$1.75, the existing Syncrude Levy, plus 80¢ to cover a portion of oil import compensation costs. The Petroleum Compensation Charge will be increased by \$2.50 a barrel on January 1 of 1981, 1982, and 1983.

Effectively, domestic refiners will be paying a blended price that is the weighted-average cost of imported oil and the various streams of domestic oil. In the process, the burden of imported oil prices will have been shifted from the taxpayer to the oil consumer. The shift will occur gradually to ensure that price increases do not result in hardship for individuals or businesses. The phase-in of the costs of imported oil was to occur at such a rate that the wellhead price plus the import cost phase-in would rise less than \$4.00 in 1980. The wellhead oil price plus the Petroleum Compensation Charge will rise by \$4.50 a barrel in 1981, 1982, and 1983. Until the blending system is fully in operation, the government will continue to provide substantial subsidies to oil consumers out of its general revenues.

Under the blended price system, Canadian oil consumers will pay prices that will rise substantially, but will remain significantly below world prices. The blended price will never exceed 85 % of the

international price or the average price of oil in the United States, whichever is lower.

The gradual nature of the shift towards full implementation of the blended price system is intended to allow adjustments to occur without serious difficulties. However, the price of imported oil, over which Canada has no control, will continue to influence the total cost of oil to the Canadian economy. Conversely, success in reducing reliance on oil imports will have a moderating effect on the blended price.

2. Natural Gas Pricing

Pricing policy for natural gas must meet two needs: provision of adequate incentive to production, and strong encouragement for consumers to use natural gas in preference to oil. Producers' returns from natural gas have risen dramatically since the mid-1970's--faster than oil prices, despite a growing surplus of gas. Producer netbacks have increased from 8 ¢ a thousand cubic feet (Mcf) in 1970 to 37 ¢ in 1975, and 94 ¢ in 1979. Thus there is already some price incentive for new gas production, and prices will continue to rise.

The producers' problem is markets. Even with the recent approvals of new gas exports, the industry will have substantial excess production capacity. In the past, the preferred outlet for surpluses has been the export market. However, the NEP aims to have surplus gas replace imported oil, requiring attractive price incentives to the gas consumer.

In the past, gas producers have enjoyed wellhead price increases as a result of a policy of raising gas prices at Toronto by 15 ¢ /mcf for every \$1.00 increase in the wellhead price of oil. This policy will continue, with the exception of 1981. In order to make room for the new federal tax on natural gas sales, which will be applied in lieu of a gas export tax, there will be a one-year pause in wellhead price increases for gas sold into the domestic market.

Because of the rise in returns enjoyed by gas producers over the last five years, this pause should not materially affect the financial well-being of the producing industry.

As in the case of oil, consumer prices for gas under the NEP will reflect a combination of taxes designed to provide revenue for the federal government, and wellhead price increases, designed to provide increased revenues to producers, and producing provinces. Gas prices to the consumer will, however, rise less quickly than oil prices in order to encourage a shift away from oil to natural gas. The federal government will establish city-gate prices for natural gas shipped inter-provincially, for all centres east of Alberta. For the three-year period commencing November 1, 1980, the price of that gas will rise 45 ¢ /mcf per year. Under previous policies, gas prices would have risen $67\frac{1}{2}$ ¢ /mcf per year as a result of a \$4.50 per year increase in the price of oil. The ratio of gas prices to oil prices will thus fall significantly over time, providing a substantial stimulus to substitution efforts.

In establishing city-gate prices, the federal government will set prices in Toronto, Montreal, Quebec and Halifax at the same level. This policy will ensure the financial viability of the pipeline to the Maritimes. City-gate prices in areas west of TransCanada PipeLines' eastern zone will be linked to the eastern Canada price, but will continue to be somewhat lower, reflecting lower transportation costs.

Within British Columbia, Alberta and Saskatchewan, the price of gas produced and consumed within the province is set by the provincial government. Federal policies may affect these prices because gas consumers in these provinces will pay the same taxes as those in the rest of the country.

3. Recent Pricing Agreements

Since the publication of documents on the National Energy Program, Ottawa and the Alberta government have reached a new agreement on oil and gas pricing, in which crude oil prices will be increased considerably more quickly than was proposed in the NEP.

Under the new agreement, as reported in the Globe and Mail,¹ the well head price will be \$33.75 per barrel by July 1, 1983, compared with \$22.25 in Alberta's earlier proposal, and \$22.75 in the NEP. Under the terms of the agreement, the wellhead price of what is called old oil (i.e. oil from fields now in production), will rise by \$2.50 per barrel at the start of October 1981 and then in regular increments every six months from January, 1982 to the middle of 1986, by which time it will be \$57.75 per barrel, (compared to the \$38.75 projected under the NEP), subject only to a ceiling of 75% of the world price.

This ceiling represents a concession on the part of Alberta. In its negotiations with the former Conservative government, a target of 85% of world levels was acceptable to both sides.

The table below shows the more recent projections of the price of conventional old oil.

FIELD PRICES OF CONVENTIONAL OLD OIL

Date	Increase	Price
Oct. 1, 1981	\$2.50	\$21.25
Jan. 1, 1982	2.25	23.50
July 1, 1982	2.25	25.75
Jan. 1, 1983	4.00	29.75
July 1, 1983	4.00	33.75
Jan. 1, 1984	4.00	37.75
July 1, 1984	4.00	41.75
Jan. 1, 1985	4.00	45.75
July 1, 1985	4.00	49.75
Jan. 1, 1986	4.00	53.75
July 1, 1986	4.00	57.75

New oil, that is, oil from newly discovered fields and oil sands plants, will be priced close to world levels and by July, 1986 will be an estimated \$77.48 a barrel to producers, subject only to a

1. Toronto Globe and Mail, September 2, 1981, page 8.

provision that it will not go higher than world levels.

The actual oil price to consumers will be a blend of the prices for the two types of oil and of world prices for imported oil. The trend will be, however, for prices to climb to world levels as production from existing fields declines and production from new sources is phased in.

Natural gas will continue to be priced low compared with the price of oil. Starting in February, it will go up be 25 ¢ per mcf every six months and Alberta will discount the price of new sales by 30% to encourage gas use. In effect, gas prices will be held at about 65% of the price of crude oil in the Toronto market.

THE NATIONAL ENERGY PROGRAM:

VI. OTHER ASPECTS OF THE NEP

There are other provisions in the NEP which will have important implications for multinational and domestic firms in the petroleum industry.

1. Oil Substitution and Conversion

Another goal of the NEP is to reduce the use of oil in each of the residential, commercial and industrial sectors in every province to no more than 10 per cent of total energy used in those sectors.

With successful completion of the 10 per cent program, oil will be used primarily in the transportation sector. Further major reductions in Canada's use of oil will come only by halting, and then reversing, the growth in demand for oil by this sector.

Also, under the NEP, the price of oil will rise to levels that make other fuels attractive on grounds of price alone. While details of the program may vary among provinces, the core program envisages grants to consumers to help cover their costs of conversions. For conversions from oil to gas, electricity, renewable, and other energy sources, a grant will be paid to consumers amounting to 50% of the conversion cost, up to a maximum of \$800.00.

2. Pipeline Extensions

Many areas of Canada are still not served by natural gas pipelines, and therefore have no opportunity to substitute natural gas for oil. In order to achieve the 10% target, the present Canadian gas transmission and distribution system will be extended, for example to Vancouver Island. The federal government has recently accepted the recommendation of the National Energy Board that the application to extend the gas pipeline system beyond Montreal to Quebec City be approved. Federal government plans are to extend this pipeline into the Maritime provinces.

3. Improving Efficiency of Crude Oil Use:

Refinery Modifications

A major element of the NEP is the modification of existing refineries to reduce to a technical minimum the production of heavy fuel oil in Canada. Heavy fuel oil can be reprocessed in a suitably designed refinery to produce higher value products such as gasoline. This process is already under way. Profit margins in the refining industry are healthy, and the commercial return on products such as gasoline should provide the necessary incentive.

As a first step in refinery modifications, the federal government has obtained commitments from four refineries to install by 1984 the facilities necessary to reduce substantially the production of heavy fuel oil. As a result of these modifications at the four refineries involved, production of heavy fuel oil should fall by some 75,000 barrels a day by 1984--adding that amount to Canada's supply of oil feedstocks, and removing unnecessary competition to non-oil fuels.

The NEP also includes a commitment by the federal government to participate financially in a heavy crude oil upgrading plant in Saskatchewan. The estimated capital cost of this plant is in excess of \$1 billion. Changes in federal income tax treatment of such plants will improve their viability. Negotiations are proceeding with a view to early establishment of a joint Canada-Saskatchewan venture involving Petro-Canada and Saskoil, and private sector heavy oil producers.

Saskatchewan Heavy Crude Oil Upgrading

The heavy crude oils of Saskatchewan and Alberta represent one of Canada's most promising avenues for sustained energy security and economic development in the region. Canadian companies have an unusually large presence in these fields. The reserves are large, nearly twice the reserves of light oil. Development has proceeded slowly, partly due to technical difficulties.

The NEP provides new price and tax incentives for production of heavy crude oil by enhanced recovery processes, as well as the refinery modification incentives mentioned above.

4. Renewable Energy

The NEP also contains provision for greater emphasis on development of renewable energy sources, such as grants for research and development in solar heating and wood products fuel, and the proposed establishment of Enertech Canada, a subsidiary of Petro-Canada supporting renewable energy and conservation technology. Efforts at conservation in the residential, industrial and transportation sector will continue under the NEP.

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SUPPLEMENTARY NOTES

UPDATE TO SUMMER 1982

I INTRODUCTION

The National Energy Program (NEP) has had a significant impact on the Canadian energy sector, particularly the oil and gas industry. The impact of the NEP, combined with prevailing market and general economic conditions, has not always been regarded as positive in terms of promoting the NEP's ultimate goals of security of oil supply, Canadianization of the oil and gas industry, and equitable distribution of energy benefits and burdens. According to some industry analysts for example, the recent collapse of the Al sands project has put Canada's future energy security in jeopardy. The Alberta and federal governments have revised their respective energy programs. This supplement is intended to pull together these major issues and events concerning the oil and gas industry which have occurred since the introduction of the NEP in October of 1980.

The "Additional Materials" contained in the casebook cover the development of the Canadian oil and gas sector up to and including the introduction of the NEP. These original materials are updated to November 19, 1981 in the Price Waterhouse (PW) booklet entitled The National Energy Program - Second Edition. This booklet includes the modifications to the NEP contained in the agreements between Alberta, Saskatchewan and British Columbia, and the federal government. Further modifications to the NEP were

announced May 31, 1982 by Marc Lalonde, Minister of Energy, Mines and Resources, in a document entitled The National Energy Program - Update 1982 (Update). This document summarizes the federal government's evaluation of the NEP and the present status of the Canadian energy sector. Most importantly however, it contains fiscal measures which the federal government hopes will revitalize the industry. Both the PW booklet and the Update are part of the course materials and so will not, in general, be duplicated in these notes. Instead, these notes are designed to complement the other materials and fill in gaps where necessary.

These notes are organized in a manner consistent with the materials in the casebook and the PW booklet. First, major issues and events in the oil and gas industry will be discussed in order to understand the reasons for the changes in governmental programs. Secondly, the recent changes in particular aspects of the NEP will be mentioned. These are organized under the same headings used in the casebook and PW booklet in order to facilitate easy cross-reference. Finally, significant legislative proposals and enactments will be examined.

II MAJOR ISSUES AND EVENTS CONCERNING THE OIL AND GAS INDUSTRY

The matters discussed here are placed in categories but the matters are not always separate and distinct.

1. Federal-Provincial Agreements

On December 10, 1981 Ottawa and Alberta executed a sub-agreement to their September 1981 pricing agreement. The sub-agreement sets out terms under which Alberta will make market development incentive payments to the federal government to facilitate expansion of natural gas markets for Alberta-produced gas in provinces east of Alberta. Payments are to be made quarterly and will be calculated as 30% of the Alberta border price multiplied by the quantity of eligible new gas delivered in the particular quarter. Payments are to cover the period from November 1981 through January 1987.

On March 2, 1982 Ottawa and Nova Scotia signed an agreement dealing with offshore resource management and revenue sharing. This agreement is similar in substance to the agreements entered into by Ottawa and the three most western provinces.

2. State of the Oil Industry

In recent years the oil industry has been optimistic in its perception of future trends in world demand and prices for oil. As a result, many oil companies went deeply into debt to finance big takeovers and new assets. Then, rather unexpectedly, interest rates skyrocketed and world oil prices fell in 1981. Now some companies are having a hard time meeting the interest payments on their massive loans. A high level of federal taxes on oil and gas production increases the financial problems of the industry. In the end, many companies had little, if any, cash flow left

With respect to the Beaufort Sea, exploration is proceeding under an agreement between Ottawa and Esso Resources Canada Ltd. completed under the Canada Oil and Gas Act, 1982. This Act requires that all leases to federal lands be renegotiated shortly after proclamation of the Act. The main objective of the Act is to speed up exploration and Canadianization by requiring large companies to relinquish part of their extensive exploration rights of federal lands and then re-issuing the exploration rights to companies, preferably Canadian, undertaking to explore the acreages.

The terms of the Ottawa-Esso agreement provide for exploration to be conducted by Esso and a consortium of ten Canadian companies. Esso's interest in the Mackenzie Delta-Beaufort Sea region is 85% with Petro-Can having the rest. To further NEP goals, the agreement calls for a significant portion of equipment to be purchased from Canadian firms, for preference to be given to northerners in hiring practices and for a gradual relinquishment by Esso of its majority interest in the land (for example, with each well drilled, the consortium will earn an interest in Esso's acreage).

Until more agreements are completed between oil companies and the federal government under the Canada Oil and Gas Act, further exploration in the frontier regions will be delayed.

4. State of Governmental Programs

(a) Recent Changes

The NEP and the provincial agreements (specific reference will be made to the Ottawa-Alberta agreement here) provide incentives to the industry to discover and develop new oil sources in that the prices for "new" oil (discovered after 1980) will eventually rise to world prices (world prices, though not as high as predicted,

are still higher than domestic prices and are still expected to continually increase in the long run). However, with respect to "old" oil (discovered prior to 1981) the Ottawa-Alberta agreement provides for less of a netback to the industry by limiting price increases so as not to surpass 75% of world price and by imposing the federal Incremental Oil Revenue Tax (IORT). Given that most production in the short run represents old oil, the lesser netbacks have aggravated the cash flow shortage of the industry. With the declared objective of alleviating this cash flow dilemma, both the Alberta and federal governments have introduced modifications to their programs.

On April 13, 1982 the Alberta government announced its Oil and Gas Activity Program specifically designed to increase short run industry cash flows. The program is operational through 1986 and is ultimately worth \$5.4B to the industry, mainly in grants and royalty reductions. In general, the reductions are most generous with respect to "old old" oil (old oil discovered prior to 1974). The highlights of the program are:

- Effective April 1, 1982 - December 31, 1986: reductions in conventional crude oil royalties estimated at \$1.71B.
- Effective April 1, 1982 - December 31, 1986: reductions in natural gas and pentane royalties estimated at \$1.93B.
- Effective September 1, 1981 - December 31, 1983: an increase in the Alberta royalty tax credit annual ceiling from \$2M to \$4M. For 1984 through 1986 the annual ceiling will revert back to \$2M.
- Establishment of a \$250M grant program for certain service and maintenance work done between April 15, 1982 and October 31, 1982.

Because the federal IORT is calculated after deduction of provincial royalties, the above reductions in royalties have the effect of

increasing IORT revenues to the federal government. However, under the Update the IORT is suspended from June 1, 1982 through May 31, 1983 so for this period at least the federal government will not benefit from this reduction in provincial royalties.

The changes introduced in the Update, along with more realistically conservative world price forecasts will result in a 49% decrease in forecasted revenues to the federal government, a 43% decrease to Alberta, and an 8% decrease to the industry, for the period 1981 through 1986. This result is in accordance with the "fair sharing" system worked out by the governments involved whereby governments get a larger share of revenue when prices and profits are high, and a substantially smaller share in periods of declining profits and revenues. In terms of revenue distribution between the two levels of government and the industry over the same period of time, the new measures shift the distribution from 29% to 22% for the federal government, from 35% to 32% for the Alberta government and from 36% to 46% for the industry. The percentages given here have all been taken directly from the Update.

(b) Start-Up of Incentive Programs

The Canadian Ownership Rate (COR) and Control Status (CS) programs were conditionally started up March 10, 1982. The Petroleum Incentives Program (PIP) was commenced conditionally on April 19, 1982. As of the summer of 1982, the PIP/COR/CS proforma applications are being accepted and processed on a conditional basis and it is expected that this will enable cheques to be issued rapidly once Parliament passes the legislation. The Alberta PIP began full operations April 19, 1982.

III CANADIANIZATION

1. Progress toward Canadianization

In a speech delivered June 2, 1982 at Laval University Marc Lalonde commented on the extent of foreign interests in Canada's oil and gas industry. According to Mr. Lalonde, since the introduction of the NEP, foreign ownership of the industry has decreased from 72% to 65.4% and foreign control has decreased from 77.7% to 67.2%.

2. Modifications to the COR/CS Programs

Between October 1981 and June 1982 the following modifications were proposed to the COR/CS programs. (Reference should also be made to the corresponding sections in the PW booklet, pages 38-42).

- Small businesses are no longer limited to total assets of less than \$5M. Instead, such businesses may have assets of less than \$20M where the full cost method of accounting is used, or less than \$10M where the successful efforts method is used.
- In determining whether an applicant is below the asset and/or revenue size which would qualify it as a small business, the assets and/or revenues of an investor which holds a private class of equity in the applicant will have to be combined with those of the applicant only where: (a) the investor is an entity (eg. a corporation) not an individual; (b) the investor participates in the control in fact of the applicant; and (c) the investor owns 10% or more of any private class of equity in the applicant. This change should make it possible for more firms to qualify for small business status and the minimal paperwork associated with it.
- Unregistered securities can be disregarded unless the issuer knows or has reason to believe their inclusion would decrease its COR.
- Two exceptions were made to the general rule that the COR certificate is effective for 12 months: (a) As long as the certificate is applied for within six months of COR legislation coming into effect, the certificate will have retroactive effect to January 1, 1981. (b) The duration of

the first COR certificate may be extended, by a random selection process, for up to six months for reasons of administrative efficiency.

- Applicants may make use of a statistical sampling approach as an alternative COR measurement technique.
- In general, less documentation is now required to be filed in support of an application than originally contemplated under the NEP.

The following measures are transitional in nature - they are effective only in the first year of the COR/CS programs. These provisions were adopted to ease compliance with the program during its early stages.

- Where investors in a public corporation have less than .5% of a class of shares, the block being worth \$50,000 or more, the investors need not contact all of their own shareholders to determine each of their COR's. Instead, the investors can compute their COR's based solely on the addresses of their shareholders.
- If, as a consequence of an event over which a COR certificate holder has control or direct influence, its COR declines then the holder need not recalculate its COR unless such a recalculation would result in a decrease of its COR to below a PIP threshold.
- The Minister of Energy, Mines and Resources (Minister) may, until December 31, 1982, fix the COR or determine the CS of a person where an application for a COR/CS certificate has been made, or where one has not been made if the Minister determines that it is in the public interest to do so, the applicant produces satisfactory evidence of his COR/CS and undertakes to apply for a certificate with all due dispatch. PIP incentives made on the basis of a transitional COR/CS will be adjusted if the COR/CS certificate differs from the transitional COR/CS.
- With respect to small block holdings by Canadian nominees (eg. banks, trust companies) on behalf of their clients, the small blocks will be automatically entitled to a deemed COR of 100%.

IV TAXATION

The following is a summary of the tax measures announced by the federal government in its Update. The purpose of these measures is to assist the oil and gas industry in Canada out of its present slump.

- The Petroleum and Gas Revenue Tax (PGRT) will be reduced from 16% to 14.67% between June 1, 1982 and May 31, 1983. This reduction will be extended to both production and royalty revenue. For production revenue, this will result in a reduction in the effective tax rate from 12% to 11% after the deduction of the resource allowance. This measure will provide approximately \$200M to the industry.
- The federal government will provide an annual credit of up to \$250,000 to corporations to offset their PGRT. It will be available to offset taxes on production revenue earned after May 31, 1982. Only one credit will be allowed for groups of associated companies, which will apportion the credit among themselves. This credit will provide an additional \$900M in cash flow to the industry in the next five years.
- The effective rate of the PGRT on production revenue from synthetic oil production from integrated oil sands plants will be reduced from 12% to 8% between January 1, 1983 and December 31, 1984. The existing oil sands plants will benefit by approximately \$125M.
- The IORT will be suspended between June 1, 1982 and May 31, 1983. This measure is worth approximately \$250M to the industry.
- The federal government is prepared to offer "earned depletion" (see PW booklet page 12) to tertiary recovery projects eligible for appropriate levels of provincial royalty relief and subject to an agreement, by the provinces, to provide information on the project justifying the relief. Eligibility for earned depletion on very large projects - those with an investment of more than \$100M - will be considered on a case-by-case basis.

V PETROLEUM INCENTIVES PROGRAM (PIP)

A review of changes to PIP since June 1981 is contained in the publication issued by the Department of Energy, Mines and Resources entitled Petroleum Incentives Program. The following is a summary of the major changes and is taken from this publication.

- Persons who apply for incentives and whose eligible costs and expenses are \$500,000 or less in a fiscal year will not be required to adjust these costs and expenses. These persons may also apply for incentives on a short form version of the PIP application. This measure does not apply where the applicant is associated with other persons whereby the aggregate of the applicant's and associates' eligible costs and expenses are more than \$500,000.
- Arrangements between farmeers and farmors involving expenditures in a calendar year which may reasonably be expected to give rise to incentives exceeding \$100M will require the Minister's written approval in order to qualify for the PIP incentives.
- If, at the time of application for incentives, the applicant is under an obligation to share the incentive with any other person, then the applicant will not be entitled to the incentive. An exception is made in the case of a trustee where the incentive is distributed to the beneficiaries of the trust.
- Eligible asset costs have been restricted to capital costs of new tertiary recovery equipment and costs of converting used equipment to tertiary recovery equipment.
- Crown corporations which are taxable will be treated as any other corporation. Persons exempt from the payment of tax under Part I of the Income Tax Act by virtue of paragraphs 149(1)(a)-(f), (h.1), (i)-(n), (t), (v), (w) or (y) are not qualified to receive incentives other than the Crown Share Incentive on Canada Lands.
- The COR of eligible applicants will no longer be reduced for PIP purposes due to the participation of tax-exempt persons except where the applicant is a partnership.
- Eligibility for incentives has been expanded to include (a) applicants with a working interest in particular areas of Canada which meet particular criteria and (b) applicants without any interest where the eligible expense is incurred as internal overhead, a drilling contribution on Canada Lands, or a geological, geophysical or geochemical expense not related to a program conducted incidentally to, and in the course of the drilling of a well.

- Now exempted from the anti-leakage rules are the eligible costs and expenses of an applicant in a situation where there exist other interested parties by virtue of an agreement of arrangement between them and the applicant as long as the other interested parties are Canadian controlled and have the required COR.
- Eligible costs or expenses incurred prior to December 31, 1986 are exempt from adjustment if incurred pursuant to an agreement entered into on or before October 28, 1980.
- Where a well is abandoned due to geological, mechanical or similar reasons, a subsequent well drilled within a reasonable time after abandonment and within reasonable proximity to the abandoned well will be considered the same well for PIP purposes.
- Where a farmee is required to reimburse a farmor for land acquisition or maintenance costs, such payments need not be deducted from the farmee's eligible expenses if (a) the costs reimbursed for were, or would have been eligible expenses; (b) the reimbursement is net of any PIP incentives, compensation or other payment received by the farmor; and (c) the reimbursement is proportional to the farmee's share of expenses subsequent to the farmout.
- Eligible costs and expenses have been expanded to include: (a) interests and financing charges; (b) scientific research expenditures; (c) integrated oil sands projects; (d) in a non-arm's length transaction, the amount by which the consideration for the acquisition of property, the use of property or the performance of a service exceeds the fair market value thereof.
- There will not be a Petroleum Incentives Board. Instead, all applications for incentives will be made to the Minister and all decisions will be taken by the Minister or his delegates.

VI PRICING

The following is a summary of the pricing measures announced by the federal government in its Update. Like the tax measures, the purpose of these measures is to assist the oil and gas industry in Canada out of its present slump.

- There will be a wellhead price increase for oil discovered after 1973 and which qualifies for provincial royalties at the new oil rates but which does not receive the New Oil Reference Price (NORP). On July 1, 1982 the price will rise to 75% of the current world price and remain at this level (subject to a ceiling of 75% of the world price) until the old oil price reaches this level. When this occurs, all old oil will again receive the old oil price. When this accelerated price is in effect the industry will benefit by almost \$100M in increased revenues.
- Beginning January 1, 1983 the NORP will be extended to existing tertiary recovery projects which pay royalties no higher than those applicable to new oil.
- The NORP will also be extended to all experimental projects which pay a royalty no greater than 5% of gross revenue and to oil wells that have been suspended for at least three years provided production from these wells qualifies for new oil royalties. Both extensions will begin January 1, 1983. The value of extending the NORP to higher cost production is approximately \$500M.

VII ENERGY LEGISLATION

Implementation of the NEP and its modifications necessitates new legislation. Some of the new legislation had been proclaimed but much was still in the parliamentary committee stage at mid-June of 1982. For present purposes only the major pieces of legislation will be mentioned.

The Canada Oil and Gas Act was proclaimed on March 5, 1982. This Act contains several provisions to promote the development of a Canadian oil and gas industry in the Canada Lands. First, the Act stipulates that Canadians, through the federal government, will retain a 25% interest in any oil and gas rights in the Canada Lands, excepting fields already in production. Secondly, the Act establishes a minimum level of 50% Canadian ownership in new oil and gas production in the Canada Lands. Thirdly, the Act sets out royalties to be paid on oil and gas revenues to ensure benefit to Canadians, through the federal government, from Canada Lands production. Finally, the Act is designed to promote the use of Canadian manufacturers, and the hiring of Canadian personnel in the development and production activities in the Canada Lands.

Major elements of the NEP were first introduced in one bill, the Energy Security Bill. Because of opposition criticism over the "omnibus" nature of the bill, it was divided into eight separate parts. These parts are summarized briefly as follows:

- An Act to amend the Petro-Can Act. This would increase the corporation's authorized capital to enable it to be active across the gamut of energy developments.
- An Act to amend the Canadian Business Corporations Act. These revisions would allow corporations to restrict ownership of existing and new share issues in order to maintain or increase Canadian ownership and control, and hence qualify for grants.

- An Act regarding petroleum incentives and Canadian ownership and control determination together with minor changes to the Foreign Investment Review Act. These revisions provide grants to encourage exploration and development of oil and gas with the richest incentives going to Canadian firms that meet high domestic ownership and control tests.
- An Act to amend the Department of Energy, Mines and Resources Act. This would create new energy corporations to hold the federal government's 25% interest in all federal oil and gas lands.
- An Act to amend the National Energy Board Act. This would broaden the powers of the board to establish energy corridors across interprovincial boundaries.
- An Act to amend the Petroleum Administration Act and enact related provisions. This would endorse a variety of tax measures already in effect.
- An Act to (a)add to the review powers of the Petroleum Monitoring Agency; (b)amend the Energy Supplies Emergency Act of 1979 to extend regulatory power to cover large-volume users who are deemed wholesale customers; and (c)amend the Oil Substitution and Conservation Act to permit grants as well as loans and guarantees to industry and consumers as part of Ottawa's "off-oil" program.
- An Act regarding vehicle fuel consumption standards. This would give legislative authority to existing voluntary standards for motor vehicle fleets.

The three parliamentary parties (Liberals, Conservatives and NDP) agreed that all the bills should be passed by June 30, 1982. As at June 15, 1982, none had been passed.

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